STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM PURSUANT TO IND. CODE § 8-1-2-42(a) TO (A) TIMELY RECOVER CHARGES AND CREDITS FROM REGIONAL TRANSMISSION ORGANIZATIONS AND NIPSCO'S TRANSMISSION REVENUE REQUIREMENTS; (B) TIMELY RECOVER NIPSCO'S PURCHASED POWER COSTS; AND (C) ALLOCATE NIPSCO'S OFF SYSTEM SALES REVENUES; (6) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS, THE ENVIRONMENTAL COST RECOVERY MECHANISM AND THE ENVIRONMENTAL EXPENSE MECHANISM; (7) APPROVAL OF THE CLASSIFICATION OF NIPSCO'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN-FACTOR TEST; AND (8) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.* TO THE EXTENT SUCH RELIEF IS NECESSARY TO EFFECT THE RATEMAKING MECHANISMS PROPOSED BY NIPSCO.	CAUSE NO. 43526 FILED AUG 29 2008 INDIANA UTILITY REGULATORY COMMISSION

Prepared Direct Testimony and Exhibits

of

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Volume 2 of 6

Robert D. Campbell, Susanne M. Taylor, William Gresham,
John M. O'Brien, Phillip W. Pack, Timothy A. Dehring

August 29, 2008

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Petitioner's Exhibit RDC-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

ROBERT D. CAMPBELL

SENIOR VICE PRESIDENT, HUMAN RESOURCES

SPONSORING PETITIONER'S EXHIBITS RDC-2 THROUGH RDC-7

VERIFIED DIRECT TESTIMONY OF ROBERT D. CAMPBELL

Q1. Please state your name and business address.

A1. My name is Robert D. Campbell and my business address is 801 E. 86th Avenue, Merrillville, Indiana 46410.

Q2. By whom are you employed and in what capacity?

A2. I am employed by NiSource Corporate Services Company ("NCS"). My current title is Senior Vice President ("SVP") Human Resources.

Q3. What are your responsibilities as SVP Human Resources?

A3. As SVP Human Resources, my principal responsibilities include oversight of all aspects of human resources for all NiSource Inc. ("NiSource") subsidiaries, including Northern Indiana Public Service Company ("NIPSCO" or the "Company"). The areas of human resources for which I am responsible include compensation and benefits, recruiting and retention, labor and employee relations, performance management, organizational effectiveness, and leadership development.

Q4. Please summarize your educational qualifications.

A4. I received a Bachelor of Arts degree from Oral Roberts University in 1981, and a Juris Doctor degree from Loyola University of Chicago Law School in 1984.

Q5. Please briefly describe your professional experience.

A5. I joined NCS in my current position in September 2005. I was previously employed by NCS as Vice President Labor and Employee Relations and Vice President Human Resources from June 2001 through January 2004. From 1986 through May 2001, I was with the law firm of Schiff Hardin, LLC in Chicago Illinois, first as an associate and then as a partner. My practice was in the area of labor and employment law. I returned to Schiff Hardin in January 2004 to oversee its professional development functions. In September 2005, I assumed my current position as SVP, Human Resources.

Q6. Have you previously testified before this Commission?

A6. No.

Q7. What is the purpose of your testimony in this proceeding?

A7. I address four topics in my testimony. First, I describe the manner in which the Company and NiSource establish overall compensation and benefits. As part of that discussion, I explain NIPSCO's base pay and incentive compensation programs and will address the market competitiveness of the Company's practices. Second, I describe NIPSCO's employee and retiree benefit programs and explain why those benefit levels are reasonable and market competitive. Third, I discuss the aging workforce issue confronting NIPSCO and the Company's pro-active efforts to address this matter. Fourth, I provide support for the pro forma adjustment made by NIPSCO Witness Linda Miller reflecting employee vacancies.

Q8. Are you sponsoring any exhibits to your testimony?

A8. Yes. I am sponsoring <u>Petitioner's Exhibit RDC-2</u> through <u>Petitioner's Exhibit RDC-7</u> which were prepared by me or under my supervision.

I. TOTAL REWARDS PHILOSOPHY

Q9. What approach does NIPSCO use to set overall compensation and benefit levels?

A9. NIPSCO, NiSource and NCS (the "Companies") utilize a "total rewards" compensation philosophy. The Companies consider all forms of compensation and benefits provided to employees in seeking to provide a "total rewards" package that is competitive within the utility industry, as well as with general industry employers, in order to attract and retain qualified employees, who provide safe, reliable and cost-effective service to our customers.

Q10. What are the components of NIPSCO's total compensation and benefits?

A10. The general components of the Company's total compensation and benefits offerings are:

- <u>Base Pay</u> – For employees who are not covered by a collective bargaining agreement, base pay is set within a range around the competitive value of the individual's job, which is established by reviewing compensation for similar positions at other utilities and general industries. Employees are also eligible for annual increases to base pay. The hourly wage and any annual increases for employees who are covered by a collective bargaining agreement are established through collective bargaining.

- Annual incentive opportunity – Nearly all employees have the opportunity to participate in the Company's annual incentive plan. The level of opportunity is established by the position held by that person. Each job is assigned an incentive range that is based on the specific requirements and scope of the job.

- Employee Benefits Program – Employee benefits, primarily retirement and health and welfare plan coverage, are a significant part of each employee's total compensation.

Q11. Does NCS employ a compensation and benefits consultant to assist it in determining the manner in which it should compensate employees across the NiSource companies, including NIPSCO?

A11. Yes. NCS regularly utilizes the services of Hewitt Associates ("Hewitt") to assist NCS in setting competitive salary ranges, establishing a program for administering salary increases, and evaluating and recommending changes to the employee benefit plans. Hewitt is well qualified to assist with the analysis of both NCS and NIPSCO's wages and benefits for a number of reasons.

First, Hewitt is a global human resources consulting firm. Hewitt serves more than 3,000 clients, including more than half of the Fortune 500®. It has access to extensive payroll and benefits market information, and analyzes the market data with respect to individual pay components and total compensation competitiveness.

Second, Hewitt is very familiar with the NiSource, NCS and NIPSCO information systems, data, personnel and corporate structure because of the long-term nature of the relationship between Hewitt and the Companies. Hewitt has provided consulting services to NiSource and its companies for a number of years.

Third, the work that Hewitt does for us is integrated with NiSource and its companies. The dynamics of the markets in which we compete for talent are always changing and Hewitt provides ongoing analysis of, and support for, the compensation and benefits plans offered by NiSource and its affiliates, including NIPSCO, in response to those market changes.

Q12. Has Hewitt helped NCS develop a competitive program for compensation and benefits?

A12. Yes. Hewitt has helped NCS implement a base pay management program to measure the reasonableness of base pay on an ongoing basis for all NiSource affiliates, including NIPSCO. Hewitt also helps measure the competitiveness of our benefit programs.

Q13. Are compensation and benefit levels at NIPSCO reasonable and competitive?

A13. Yes. As I will explain throughout my testimony, NIPSCO provides reasonable and competitive compensation and benefits.

II. BASE COMPENSATION

Q14. Is NIPSCO required to provide any increases as a result of labor contracts?

A14. Yes. NIPSCO has two collective bargaining agreements which require annual increases through the terms of the agreements. The terms of those agreements are from June 1, 2004 through May 31, 2009.

Q15. When do increases under the collective bargaining contracts take effect for each of NIPSCO's bargaining units?

A15. Petitioner's Exhibit RDC-2 (Union Wage Rate Increases) sets forth the scheduled wage increases in the two collective bargaining agreements. Both contracts provided for a 3.0% base wage increase effective immediately at the conclusion of the calendar year ending December 31, 2007, and for an additional 3.0% wage increase effective immediately at the conclusion of the calendar year ending December 31, 2008.

Q16. How is base pay determined for employees who are not covered by a collective bargaining agreement?

A16. NCS, on behalf of NIPSCO, compares the base pay for NIPSCO's employees against the base pay offered to employees in similar positions at other companies. NCS uses this market data to establish a pay range for each position. The established salary range for each NIPSCO job spans from 75% (minimum) to 125% (maximum) of the market median. An employee's placement within the applicable range is determined by factors such as general business conditions and the employee's skill set, experience, and performance.

Q17. Does NIPSCO provide annual increases to its employees who are not covered by a collective bargaining agreement?

A17. Yes. As shown on <u>Petitioner's Exhibit RDC-3</u> (Performance Adjustment Increases), NIPSCO has regularly awarded annual pay increases to such employees. Effective March 1, 2008, NIPSCO provided a 3.25% performance pay pool for distribution to employees. Leaders are expected to differentiate the amount of increase provided to individual employees based upon the employee's individual performance and contribution, as well as the employee's relative placement in the salary range for his/her position. Thus, while individual increases were more or less than 3.25%, the average increase for all employees was 3.25%.

III. ANNUAL INCENTIVE PLAN

Q18. Does NIPSCO also provide employees an opportunity to receive annual incentive pay?

A18. Yes. NIPSCO and NCS have an incentive compensation plan that is designed to drive focus on the Company's goals and reward employees' performance. Our Companies' goals are documented on performance management worksheets and are divided into four key categories: Customer; Employee; Financial; and Process/Capability. This goal setting process is critical in reinforcing key initiatives, including safety, customer service, operational efficiency, and continuous improvement.

Q19. Is the potential to earn incentive pay needed for NIPSCO and NCS to be effective in recruiting and retaining employees?

A19. Yes. Incentive compensation is an element of competitive total compensation in the labor market both within the utility industry and within the broader employer base. Incentive pay is also a factor in determining an employee's total cash compensation. As I discuss below, when we examine whether our total compensation is competitive, incentive pay is one of the components of compensation we compare to the external market. Further, as part of my responsibilities, I am involved in recruiting people to join the Companies. The incentive compensation opportunity with the Companies is a factor in our ability to recruit successfully. Therefore, to remain competitive in the labor market, NIPSCO must provide the potential to earn incentive compensation. Alternatively, in the absence of an incentive opportunity NIPSCO would need to adjust base salaries upward to avoid falling behind its competition for labor. Hewitt indicates that, by 2007, nearly 90% of U.S. companies had implemented a broad-based variable pay plan.

Q20. How are NIPSCO incentive levels and incentive ranges determined?

A20. Each employee is placed in a job scope level which is based generally on his or her responsibility level within the organization. Each job scope level, in turn, has an incentive range attached to it. This incentive range defines the opportunity that an employee in that position has for an incentive payout under the annual incentive plan. The associated incentive range starts at the "trigger" level and increases through "target" and up to "stretch" or maximum. An example of how incentive levels and ranges are implemented follows:

> First line supervisors are in a job scope level that provides a target incentive of 10% of base pay. The trigger and stretch levels are 50% below and above the target percentage, respectively. Therefore, the incentive range for a first line supervisor is:

5%	10%	15%
Trigger	Target	Stretch

Q21. How does the incentive plan work for NIPSCO employees?

A21. For 2008, certain goals were set for both overall NiSource and for the business segment of which NIPSCO is a part. If these financial goals are met, an incentive pool is created for distribution to NIPSCO employees. For employees covered by a collective bargaining agreement and for other non-exempt employees, their incentive pay is determined arithmetically by multiplying their incentive payout percentage times their eligible earnings. For all other employees, one-third of their incentive pay is determined arithmetically by multiplying their incentive payout percentage times one-third of their eligible earnings. The other two-thirds of their incentive is determined by assessing how well that employee has met his/her individual performance objectives.

Q22. When is incentive compensation awarded?

A22. If the measures for the incentive plan are met, incentive compensation is delivered annually in the end of February paycheck for monthly paid employees and in the first paycheck in March for bi-weekly paid employees.

Q23. Does NIPSCO pay incentives in most years?

A23. Payment of an incentive depends upon whether the established criteria are achieved. Based upon achievement of the incentive compensation standards, NIPSCO paid incentives to employees in three of the past four years.

IV. <u>DETAIL OF COMPARATIVE COMPENSATION ANALYSIS</u>

Q24. Have you performed a comparative analysis to determine the reasonableness of NIPSCO's total cash compensation?

A24. Yes. As previously mentioned, NCS, in conjunction with Hewitt, has prepared comparative analyses that compare total cash compensation provided by NIPSCO and NCS relative to other investor-owned utilities and to general industry companies. Hewitt provides NCS with robust external compensation data that is utilized for comparison purposes. The analyses look at base compensation and "total cash compensation." "Total cash compensation" is the total of base pay and incentive pay. These analyses show that the base pay and total cash compensation provided by NIPSCO and NCS are reasonable when compared with other applicable utilities and general industry employers.

Q25. Please explain the overall approach to this analysis concerning the reasonableness of NIPSCO's compensation.

A25. In preparing the comparative analyses, I used the Hewitt external compensation data and examined a sampling of several NIPSCO positions. I compared the base salaries and incentive pay for those NIPSCO positions against base pay and incentive pay for similar external positions. In addition, a similar analysis was done for a sampling of NCS positions.

Q26. Please review the comparative analyses performed in relation to total cash compensation.

A26. Petitioner's Exhibit RDC-4 (Comparison of NIPSCO Base Salaries and Total Compensation) provides a comparison of base salaries and total compensation for several NIPSCO positions to the base salaries and total cash compensation for similar positions in the marketplace. As I already described, NIPSCO's external compensation consultant, Hewitt, provides the external market data.

Q27. What were the results of your analysis?

A27. Petitioner's Exhibit RDC-4 (Comparison of NIPSCO Base Salaries and Total Compensation) shows that the average base salary paid by NIPSCO for these positions is $77,500, and total cash compensation is $81,500, as compared to external data showing an average base salary of $81,300 and total cash compensation of $88,000.

Q28. What conclusion do you draw from this analysis?

A28. NIPSCO's base salary and total cash compensation are reasonable and competitive. Specifically, NIPSCO is 4.6% below the market comparison data in base pay and 7.4% below in total cash compensation for these NIPSCO positions.

Q29. Please describe <u>Petitioner's Exhibit RDC-5</u> (NCS Base Salaries & Total Compensation).

A29. While <u>Petitioner's Exhibit RDC-4</u> was specific to NIPSCO employees, <u>Petitioner's Exhibit RDC-5</u> compares the base salaries and total cash compensation for certain NCS positions with external market data.

Q30. What conclusions do you draw from <u>Petitioner's Exhibit RDC-5</u> (NCS Base Salaries & Total Compensation)?

A30. <u>Petitioner's Exhibit RDC-5</u> (NCS Base Salaries & Total Compensation) shows that the average base salary paid by NCS for these positions is $66,700 and total cash compensation is $70,300, as compared to the Hewitt external data that reveals an average base salary of $69,000 and total cash compensation of $73,100. Overall, NCS base salaries are 3.2% below, and total cash compensation is 3.9% below the Hewitt market data. Based on this analysis, I conclude that NCS's base compensation and total cash compensation are both competitive and reasonable.

V. <u>ANNUAL BASE PAY INCREASES</u>

Q31. How do annual base pay increases at NIPSCO compare to those provided by other employers?

A31. Petitioner's Exhibit RDC-6 (Merit Increase Comparison) provides a comparison between NIPSCO's 2007 and 2008 base pay increases (as a percent of base pay) for employees who are not covered by a collective bargaining agreement and those for other utilities and general industry employers. The data in Petitioner's Exhibit RDC-6 is also categorized nationally and regionally. This analysis draws from Hewitt data covering a large number of companies within the utilities industry, general industry and industries located in the Midwest.

Petitioner's Exhibit RDC-6 demonstrates that the Company's annual increases in 2007 of 2.5% (non-exempt) and 3.0% (exempt) were below the average increases of other companies within the region and the utility industry (3.5% to 3.6%). Similarly for 2008, the annual increases of 3.25% (non-exempt) and 3.25% (exempt) are below what is being projected by other companies within the region and the utility industry (3.6%).

Q32. When do annual increases for employees take effect?

A32. NIPSCO's employees who are not covered by a collective bargaining agreement receive annual base pay increases effective March 1 of each year.

Q33. Is it NIPSCO's practice to provide merit increases consistently every year?

A33. Yes, NIPSCO has provided merit increases each of the past 4 years. These increases are important to recognize employees' contributions and to allow NIPSCO to remain competitive. Annual base pay increases are a critical component to attracting and retaining a high quality workforce.

VI. EMPLOYEE BENEFITS

Q34. What are the benefits offered by NIPSCO to attract and retain qualified employees?

A34. Benefits are an important component of any compensation structure and are necessary to ensure NIPSCO is able to attract and retain qualified employees. NIPSCO's benefit plans basically correspond to the plans offered throughout the NiSource system, including health and welfare plans (health care coverage, dental coverage, vision care, term life insurance and disability insurance), a defined benefit pension plan, a 401(k) savings plan, and paid time off (vacation, holiday and sick pay).

Q35. Please describe each of the major plans.

A35. The major benefit plans are as follows:

1. Pension Plan

Pension benefits are provided to NIPSCO employees and certain NCS employees pursuant to the provisions of the NiSource, Inc. and Northern Indiana Public Service Company Pension Plan Provisions Pertaining to Salaried and Non-Exempt Employees and NiSource, Inc. and Northern Indiana Public Service Company Pension Plan Provisions Pertaining to Bargaining Unit Employees ("Pension Plan"). The Pension Plan consists of four different pension offerings. The particular pension offering in which an individual participates is determined by factors such as whether the employee is in a bargaining unit, the date of the employee's hire, and/or individual choice. The four different pension offerings are: (1) the Account Balance 2011 formula; (2) the Account Balance formula; (3) the salaried/non-exempt Final Average Pay formula; and (4) the bargaining unit Final Average Pay formula.

The manner in which the pension benefit is calculated varies according to the pension offering. Under the Account Balance 2011 Formula, pay credits are allocated to an employee's balance in an amount equal to a percentage of the employee's eligible pay. The employee's annual pay credit percentage is determined by the total age and service points the employee accumulates each year, as measured on December 31. The pay credit percentage ranges from 4 to 6 percent of eligible pay. In addition, an employee receives an additional pay credit in the amount of 1 percent of eligible pay that is above the social security taxable wage base in effect that year. In addition to the pay credit, employees receive an interest credit to their account each year on December 31.

Under the Account Balance Formula, pay credits are allocated to an employee's balance in an amount equal to a percentage of the employee's eligible pay. The employee's annual pay credit percentage is be determined by the total age and service points the employee accumulates each year, as measured on December 31. The pay credit percentage ranges from 5 to 10 percent of eligible pay. In addition, an employee receives an additional pay credit in the amount of 2 percent of eligible pay that is above the social security taxable wage base in effect that year. In addition to the pay credit, employees receive an interest credit to their account each year on December 31.

Under the salaried/non-exempt Final Average Pay formula, an employee receives a pension benefit that is based upon: 1.7 percent of the employee's final average pay times years of credited service up to 30; plus, 0.6 percent of final average pay times years of service over 30.

Under the bargaining unit Final Average Pay formula, an employee receives a pension benefit that is based upon: 0.575 percent of final average pay times years of credited services up to 30; plus, years of credited service times an amount based on the employee's benefit class for the last 60 months.

The annual expense of the pension is based upon calculations performed by Hewitt Associates consulting actuaries. The annual expense is determined by factors including the discount rate, return on assets, and various actuarial assumptions. Hewitt also makes an annual evaluation of the pension plan as to liabilities, assets and the required funding level.

2. <u>NiSource Inc. Retirement Savings Plan and Northern Indiana Public Service Company Bargaining Unit Tax Deferred Savings Plan</u>

Employees can contribute 1% to 50% of eligible compensation on a pre-tax basis and up to 25% on after-tax basis, subject to IRS limitations.

The Company matches a portion of the pre-tax or after-tax contributions each pay period. The amount of the Company's match varies based upon the pension plan offering in which the employee participates.

3. Medical Coverage

NIPSCO provides medical coverage to its employees through the following self insured plans: USWA Indemnity Plan; Standard Plan 1; Preferred Provider Organization (PPO); and two High Deductible PPOs.

NIPSCO continues to review plan coverage and to search for more efficient ways to offer and administer plan coverage. NIPSCO now offers two high deductible PPOs with corresponding health savings accounts. The Company self-insures its PPO offerings and indemnity plans, which reduces underwriting margins. Plans that offer coverage through provider networks are used as often as possible to take advantage of provider discounts.

NIPSCO also provides access to medical coverage for retirees who meet certain age and service requirements. The amount of subsidy NIPSCO provides to retirees varies depending upon factors such as: whether the employee is a member of a bargaining unit; the number of years of service; the level of coverage; and when an employee retired.

4. Dental Coverage

NIPSCO offers three dental coverage options: (1) Preventative Dental (salaried/non-exempt only), (2) Basic Dental; and (3) Dental Plus. All dental plans use a network of providers. The process of procuring dental coverage for NIPSCO employees corresponds with the process for procuring health care described previously. The efforts undertaken to control dental costs are the same as those described previously for health care.

5. Vision Coverage

NIPSCO provides Vision coverage to its employees. The Plan utilizes a network of doctors. The plan covers certain costs associated with exams and correction.

6. Group Life

The Companies provide three forms of life insurance: Basic Group Life; Accidental Death and Disbursement ("AD&D"); and Retiree Life Insurance. Group Life and AD&D are based upon covered base compensation for salaried and non-exempt and years of service for bargaining unit employees. Retiree Life is a fixed amount. As with all NIPSCO's insured plans, the premiums are based upon actual claims experience because this is a fully experienced-rated plan.

7. <u>Long Term Disability ("LTD")</u>

The cost of LTD is based on an employee's base compensation. The LTD plan is also fully experience-rated and, therefore, the premium reflects NIPSCO's claims experience plus administrative expenses. For bargaining unit employees, the applicable disability plans and coverage level depends on date of hire.

8. <u>Employee Assistance Program</u>

EAP provides short-term counseling for employees and their dependents to assist with personal, family and work-related concerns.

A. <u>Health Care and Dental Plan Costs</u>

Q36. How does NIPSCO obtain the various health care coverages for NIPSCO employees?

A36. NCS provides a number of health care coverage options for NIPSCO employees and retirees. Applicable benefit plan coverage is competitively bid through a request-for-proposal process. Proposals are solicited from insurance carriers and/or third party administrators. These proposals are reviewed and finalists are selected based upon the financial stability of the carrier or third-party administrator, the breath of its provider network, network provider discounts, administrative capabilities, and price. Finalists are interviewed and further negotiations take place regarding pricing for the services offered. Carriers and third-party administrators are selected based upon their ability to provide quality service in the most cost-efficient manner.

Q37. What steps has NIPSCO taken to manage its health care costs?

A37. NCS, on behalf of NIPSCO, undertakes many initiatives to manage the cost of providing health care to NIPSCO employees. NCS continues to review plan coverage and to search for more efficient ways to offer and administer plan coverage. The primary health care plans are self-insured, which reduces underwriting margins. Plans that offer coverage through provider networks are used as often as possible to take advantage of provider discounts. Opt-out credits are paid to those employees who have alternate health care coverage and elect not to participate in the plans. These credits are offered at a fraction of the cost that would otherwise be required to provide coverage for the employees who opt-out.

As with other parts of its business, NIPSCO realizes some purchasing power to ensure competitive rates from its carriers because of its affiliation with NiSource. In addition, corporate-wide programs offer a larger pool of covered participants, which provides for a larger spread of risk. The larger risk pool helps manage health care costs.

Q38. Does that mean that employees are subject to increases commensurate with those imposed on NIPSCO?

A38. Yes. Because employees share on a percentage-of-cost basis in the cost of the health plans that NIPSCO makes available to them, employees have experienced increases in their contributions toward health coverage. Additionally, the percentage of cost employees share increased from 15% to 20% for non-exempt employees in 2008. Exempt employees are paying 30% of the cost in 2008, the same percentage as 2007. For employees in the bargaining units, their percentage cost share is 15% and is subject to collective bargaining.

Q39. How does NIPSCO procure dental coverage for its employees?

A39. The process of procuring dental coverage for NIPSCO employees corresponds with the process for procuring health care described previously.

B. <u>Retiree Benefits</u>

Q40. Please describe the post-retirement benefits other than pensions that NIPSCO provides to its retirees?

A40. NIPSCO also provides access to medical coverage for retirees who meet certain age and service requirements. The amount of subsidy NIPSCO provides to retirees varies depending upon factors such as: whether the employee is a member of a bargaining unit; the number of years of service; the level of coverage; and when an employee retired.

NIPSCO also provides life insurance to its retirees. The amount of life insurance coverage is fixed.

C. <u>Competitive Benefits</u>

Q41. How does NIPSCO assess how its employee benefit plans compare to other companies?

A41. On behalf of NIPSCO, NCS periodically performs studies to compare benefits at a program level and as a package against the benefit programs of a market basket of similar offerings at other employers. The standard NIPSCO benefit offerings are compared to the benefits offered at other energy companies, including investor-owned utilities, and separately against offerings at companies in general industry. The total value and the employer-paid portion of the benefits are rated on a standardized value scale that reflects the deviation of the NIPSCO standard benefit offerings against the average of the selected cohort. In addition to the studies, employees within the NCS Human Resources department along with Hewitt and its other benefits vendors, conduct ongoing evaluations regarding benefits trends that are observed in the marketplace, as well as alternative means of reducing the cost of providing the necessary benefits.

Q42. What were the results of the latest Hewitt study performed regarding NIPSCO's benefits offerings?

A42. The results of the study recently performed by Hewitt in May 2007 show that the overall employer-paid value of NIPSCO's benefits plans is 0.1% higher than the average of the selected energy industry cohort. As compared with general industry, the employer-paid value of NIPSCO's benefits is 2.4% higher than the study group. Based on these results, I conclude that NIPSCO's benefits are competitive and reasonable as compared with the offerings from other employers in the labor market.

VII. AGING WORKFORCE

Q43. Please briefly address the issue of an aging workforce.

A43. The aging workforce issue is confronting utilities and other industries in the U.S. and Indiana, including NIPSCO. Experienced baby boomers are reaching retirement age in the next few years and are projected to leave the workforce. In general, projected retirements at NIPSCO over the next five years will make it necessary to fill certain critical positions ahead of time to allow for formal and on-the-job training. This approach will also enable NIPSCO to complete portions of apprentice-based and all line-of-progression training, as well as other on-the-job training, so that trained employees will be ready to effectively replace retirees as they depart the Company. I will describe the efforts that NIPSCO has undertaken to address this phenomenon. NIPSCO Witness Timothy A. Dehring will also discuss this issue in his testimony.

Q44. Can you describe the nature of the aging workforce phenomenon?

A44. Yes. This phenomenon is not affecting NIPSCO alone; again, it is a challenge that is facing many other utilities and industries as well. The baby boomer generation (a demographic term for those individuals born between 1946 and 1964) reaches 44 to 62 years of age during 2008. Many in this age group (comprising 82,826,479 individuals, according to data from 2000 U.S. Census estimates) will be retiring over the next several years.

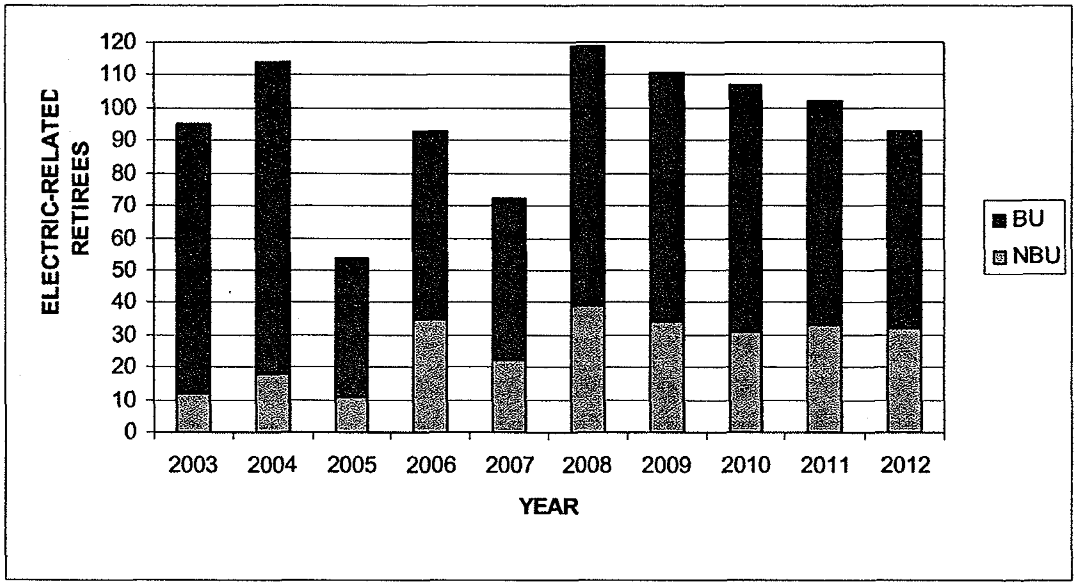
U.S. Bureau of Labor statistics in 2003 calculated the median age of electric power generation, transmission, and distribution employees at 43.7 years of age, which at the time was 3.3 years older than the median age for all persons employed in the U.S. At NIPSCO, as of the end of 2007, the median age of all electric-related employees was 50.0, which is considerably higher than the rest of the electric utility industry and the U.S. workforce in general.

The loss of the knowledge base held by experienced and highly trained employees in large numbers from critical job positions over a short period of time can adversely affect a company's ability to operate effectively. Addressing the issue properly and in a timely manner is critical in maintaining the industry skill set needed for the delivery of safe, reliable and effective service to NIPSCO's electric utility customers.

Q45. How in particular does the aging workforce phenomenon affect NIPSCO?

A45. NIPSCO pension and other benefits policies and the collective bargaining contracts have essentially defined an eligible retirement age bracket that begins at 55 years of age. For non-bargaining unit employees, besides the minimum age requirement, the prospective retiree must also have at least 25 years of service. Bargaining unit employees must have a total of 85 points (age plus years of service) in addition to being at least 55 years old. At year end 2007, approximately 26% of NIPSCO's electric-associated workforce was in this eligible retirement age bracket. Those employees that are at least age 50 years of age comprise nearly 51% of the same workforce complement, and over the next 5 years, the 50-54 year old employee group will also enter into the 55-and-above eligible retirement age bracket. Thus, over one-half of the current NIPSCO electric utility-associated workforce will have been in the retirement age bracket by the end of 2012. This percentage is even higher for electric-associated management employees, where over 57% of that workforce will have been in the retirement age bracket in the same time period.

In the past five years (2003-2007), 428 retirement-eligible electric utility-related employees elected to retire from NIPSCO. The terms of the physical and clerical bargaining unit contracts were renegotiated in 2004, and NIPSCO experienced an increase that year in bargaining unit retirements over the previous year, followed by a drop in 2005. The year 2009 is also a contract expiration year, and this will most likely affect the number of bargaining unit retirements in 2009 and 2010 as it did in 2004 and 2005. Projections using the recent past retirement rates by age (55 through 66+) as predictors for the future indicate that overall, of the 830 electric utility-related employees who are expected to be eligible for reduced-benefit or full retirement over the next five years, about 532 (64%) will elect to retire by the end of 2012. The following charts show the past five years actual and also segments the expected retirements commencing in 2008 through 2012, shown by bargaining (BU) and non-bargaining (NBU) unit employees. The larger number of employees projected to retire over the years 2008 through 2012 is for the most part a direct result of the surge in the population of retirement-eligible baby boomer generation employees.



Bargaining Unit Employees

Years	Projected Retirements	# of Eligible Employees	Percentage of Eligible Employees
2008	80	311	25.7
2009	77	298	25.8
2010	76	294	25.9
2011	69	279	24.7
2012	61	253	24.1

Non-Bargaining Unit Employees

Years	Projected Retirements	# of Eligible Employees	Percentage of Eligible Employees
2008	39	182	21.4
2009	34	165	20.6
2010	31	158	19.6
2011	33	149	22.1
2012	32	138	23.2

Q46. What has NIPSCO done over the past few years to ensure the continued availability of a skilled workforce?

A46. Over the past five years, NIPSCO has identified the bargaining unit positions with key skills that are critical to the safe, reliable and effective day-to-day operation of its electric generation, transmission & distribution systems. Feeder positions into these critical jobs have also been identified, and so on, back to the entry-level positions. An emphasis has been placed on the timely filling of retirement-related vacancies that arise in the critical and related positions throughout NIPSCO through the continued use of an annual "mega-bid" process.

In the fourth quarter of each year, an assessment is made of the bargaining unit employees that are likely to retire, in the critical areas and in general. Projections of departures by prospective retirees along with predictions of the resulting employee migration among affected departments allow the creation of a job-needs complement for the following year. Bids are posted for all positions that would be vacated due to retirements, along with the positions that could become vacant due to subsequent migration, in January. The awarding of returned bids is managed according to the timing of the need for replacements, allowing extra time for training through "fill in advance" bid awards. The mega-bid process helps create a master plan to streamline the subsequent filling of bargaining unit jobs. Criteria have also been established for the assessment and testing of individuals who are hired from outside the Company to backfill entry-level bargaining unit positions, such as meter reader or part-time customer service representative. The mega-bid process also allows for the establishment of a reasonable pool of eligible new hires for the entry positions.

Succession planning programs, with their inherent opportunities for mentoring as well as cross-training, have helped to accomplish a similar critical-position emphasis for other employees. NIPSCO also has a summer intern program by which it exposes individuals to NIPSCO's electric and gas utilities. NIPSCO has also retained the services of a limited number of retired employees as part-time contractors, for example in engineering, to help mentor younger engineers and to perform critical engineering and design work on a project basis. Additionally, NIPSCO ramped up its training program for linemen during 2007 in response to the need for the hiring and training of more linemen in 2008 and beyond, as increased retirements are anticipated to occur.

NIPSCO has also partnered with outside entities, such as Ivy Tech Community College of Indiana, to help create a pipeline of eligible individuals within the general public. NIPSCO is a founding member of a consortium comprising: Indiana rural electric member corporations; other municipal and investor utilities; Workforce Development Boards; a large gas industry contractor; and representatives from various Ivy Tech Community College of Indiana campuses. This effort began in 2006, the purpose of which is to attract, educate, and prepare workers for positions in the electric and gas utility industry.

In the past two years, common curricula have been developed for a number of critical skill areas, including power plant positions and electric line workers. Ivy Tech will offer the training at its campuses throughout the State, and the consortium membership will, in turn, interview the graduates for prospective jobs within their companies. Early in 2008, NIPSCO began working directly with Ivy Tech to refine curriculum content, select instructors, identify necessary training equipment, design a marketing plan and materials to attract students and begin the classroom training at local campuses. Additionally, as a result of the efforts of NIPSCO and the other consortium members, Ivy Tech will receive a $1 million grant over three years to support this program to train utility industry workers statewide. Local Ivy Tech training courses will begin in the near future and will provide NIPSCO with opportunities to attract capable and interested graduates to positions that will need to be filled due to the retirement of our aging workforce.

The aging workforce issue is being addressed in a similar manner within NIPSCO's natural gas business. As NiSource SVP, Human Resources, I can say that the NIPSCO Human Resources department has provided ongoing direct support for all of these efforts, and will continue to do so.

Q47. What are the critical positions on which NIPSCO will focus for the foreseeable future?

A47. In the management and professional areas, the critical positions in the generation, transmission and distribution systems and operating areas include: first-line supervisory positions; design/operating engineering positions; and generating and transmission system operating positions. The bulk of these positions are in: the distribution operations, maintenance, engineering and field services areas; the generation operations, dispatch, and engineering area; the transmission operations and engineering areas; and the trading and energy management department.

In the transmission and distribution operations area, critical positions within the represented workforce include: lineman; substation electrician; meterman; and dispatcher operator. In the generating stations, major critical positions include: station mechanics; instrument and chemical technicians; and station and unit operators. Part-time customer service representative positions in the customer service center have proven to be critical as they are entry-level positions that feed clerical bargaining unit vacancies throughout the Company.

Q48. What are the plans for hiring individuals in the critical positions?

A48. Recruiting for critical management positions has been stepped up in an effort to bring a replacement on board before the incumbent employee retires. The early hiring will allow a replacement to come up to speed faster by using the retiring employee as a dedicated mentor. The timing for the early hiring varies from six months to one year, depending upon the skills required for the position. Some replacements that come from inside the company are identified in the succession planning program, which also allows for an early backfill of a soon-to-be-vacant position.

Timely recognition of replacement needs for bargaining unit jobs from projected retirements allows for early bidding of critical position locations for apprentices, for example, and to begin training programs ahead of time. Hence, when a vacancy occurs, NIPSCO is able to fill the position with an employee who is able to provide a degree of productivity and ready to assume a higher level of responsibility than a new apprentice would be able to. Bidding for these jobs typically creates vacancies in entry-level positions. NIPSCO intends to fill the resulting entry-level positions from the pool of successfully tested and assessed individuals created by training programs such as the one with Ivy Tech.

Q49. Will the aging workforce issue require significant additional support from the Human Resources departments in NIPSCO and NCS?

A49. Yes, NIPSCO will require significant support from the Human Resources department. This department has used, and will continue to use, an optimized blend of employees and outside contract services to provide the most cost - effective support to the NIPSCO workforce.

Q50. What are the costs associated with the early identification and hiring of the critical position replacements?

A50. The costs associated with the early hiring of replacements for critical positions come primarily from the double staffing that occurs during the apprentice, training, and job shadowing periods, when both the replacement and the incumbent employees essentially are in the same position. The additional payroll costs for the replacement employees are adjusted by a benefits multiplier that covers the cost of employee benefits. These costs are further adjusted to subtract capital-related costs, and in the case of dual (electric/gas) employees, an electric allocator is used to apportion the electric-related cost. Training costs that were not covered in the 2007 test year are also added to the total cost figures. All costs are calculated over the five-year period from 2008 through 2012, and averaged for the proposed adjustment to the test year figures. Petitioner's Exhibit RDC-7 shows the total costs and also breaks down the costs by category identified in this response.

Q51. What are the possible consequences if the positions identified above are not filled?

A51. Day-to-day performance levels of the generating stations could deteriorate. Forced outage rates, megawatt output, and capacity factors, for example, are at risk by the loss of an adequate complement of skilled operating and maintenance personnel, who are needed to continue to operate and maintain the generating plants at the levels required for NIPSCO's customers.

Similarly, NIPSCO needs to maintain a cadre of skilled workers for effective day-to-day maintenance of the transmission and distribution systems. Many of the positions are front-line positions that interface directly with customers. For example, these positions cover tasks including equipment inspections, switching operations, maintenance of substations, overhead and underground electric delivery equipment, and service restoration following storms or other outage causes. Because the Company wants to ensure the continued provision of safe, high quality and reliable customer service, it is vital that these positions be filled by qualified employees. Although contractors can be used to fill gaps in construction labor needs or to help in service restoration after a storm, a balanced skilled-employee/contractor mix is needed for effective day-to-day service safety and reliability. If these positions are not filled, overall system reliability could indeed suffer, which could also reduce the level of service provided to NIPSCO customers. NIPSCO's ability to provide safe, cost-effective and reliable electricity to its customers requires the maintenance of a trained and highly-skilled workforce, especially in the critical positions discussed above.

Q52. Please explain why the adjustment for this workforce is reasonable.

A52. NIPSCO endeavors to keep rates low by managing employee numbers to the lowest reasonable level. When employees have left the Company, NIPSCO replaces only those jobs that are necessary. The use of company-wide maintenance and construction groups in generation, transmission and distribution has also helped to keep the local area workforce levels reasonably low. However, as explained above, that strategy is affected by the need to match future workforce levels to the needs of its systems and its electric customers. By focusing on early replacement of critical positions and their backfills, this approach can continue to provide safe and reliable service at reasonable cost. Also, a good balance of journeymen to apprentices can be managed to facilitate effective on-the-job training. A reasonable contractor to skilled employee mix can be maintained to ensure that local expertise is in place for effective day-to-day operation of the generating stations and the transmission and distribution system. Contractors will still be used as appropriate for certain construction projects and for assistance in quick storm restoration in order to maintain system safety and reliability. While these additional employees and training costs result in cost increases, adding the employees and providing targeted training is a reasonable approach resulting in the ongoing provision of safe and adequate service at just and reasonable rates.

VIII. <u>VACANCIES</u>

Q53. Would you please address the vacancies that are reflected in the pro forma adjustment made by Ms. Miller?

A53. Adjustment OM-8 included in <u>Petitioner's Exhibit LEM-2</u> to NIPSCO Witness Linda E. Miller's testimony is to increase operation and maintenance expense in the amount of $5,016,101. This adjustment reflects additional staffing required to fill current vacancies in positions that NIPSCO is actively in the process of securing candidates. This amount was calculated by obtaining a list of 104 vacancies from the Human Resources department and applying the appropriate hourly wage for each bargaining unit position, and the appropriate salary amount for each supervisory position. Benefits were then added, as well as incentive compensation based on the incentive range for the position level. The resulting amount was $9,561,015. Vacancies for electric-specific positions were identified as such, and common positions were allocated to electric based on the established common allocation ratios. After determining the electric amount and deducting for the portion capitalized, the net adjustment was an increase (debit) to electric operation and maintenance expense of $5,016,101.

Q54. What is the process the Company uses to fill vacant positions?

A54. The Company's typical practice in filling vacancies that are not covered by a collective bargaining agreement is to post these positions internally, as well as on its external website. For internal postings, individuals can apply by responding to the posting on the company intranet. For external postings, individuals can express interest by responding to the posting online. Positions covered by a collective bargaining agreement are posted on all NIPSCO Union Bulletin Boards. If a position is not filled by a successful bidder, the Company can fill the vacancy externally within 45 days. Entry level positions, such as Meter Readers, Construction Helpers and Customer Service Representatives are also always posted externally, on both the Company website, as well as in local newspapers.

IX. CONCLUSION

Q55. Does this conclude your prepared direct testimony?

A55. Yes, it does.

VERIFICATION

I, Robert D. Campbell, Senior Vice President, Human Resources for NiSource Corporate Services Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Robert D. Campbell

Date: August 29, 2008

INDS01 DWM 1060949v4

Petitioner's Exhibit RDC-2
Northern Indiana Public Service Company
Cause No. 43526

Union Wage Rate Increases

	2005	2006	2007	2008	2009
United Steelworkers Local Union 12775 (physical)	1-Jan	1-Jan	1-Jan	1-Jan	1-Jan
	2.50%	3.00%	2.50%	3.00%	3.00%
United Steelworkers Local Union 13796 (clerical)	1-Jan	1-Jan	1-Jan	1-Jan	1-Jan
	2.50%	3.00%	2.50%	3.00%	3.00%

Performance Adjustment Increases

	2005	2006	2007	2008	2009
Exempt	1-Mar	1-Mar	1-Mar	1-Mar	1-Mar
	2.00%	3.00%	3.00%	3.25%	NA
Non-Union Non-Exempt	1-Mar	1-Mar	1-Mar	1-Mar	1-Mar
	3.00%	3.00%	2.50%	3.25%	NA

Comparison of NIPSCO Base Salaries & Total Compensation

Position	1/ NIPSCO Annual Base Salary (000's)	1/ NIPSCO Annual Total Cash Comp (000's)	General Industry Annual Base Salary 2/ (000's)	General Industry Annual Total Cash Comp 2/ (000's)
Engineer 3	$85.6	$89.6	$93.1	$97.3
Engineer 1	$62.4	$64.4	$65.5	$69.0
Supv Operations	$81.6	$86.6	$84.1	$93.5
Transmission System Supv-Ops	$81.5	$85.4	$78.5	$86.0
Supv Maintenance	$78.4	$82.5	$84.1	$93.5
Supv Substation	$79.1	$83.3	$81.5	$88.3
Area Supv Field Services Line	$77.3	$82.2	$81.5	$88.3
Supv Coal Handling	$76.7	$81.3	$84.1	$93.5
Operation Analysis Eng 2	$77.9	$81.1	$80.1	$85.3
Maintenance Planner	$74.8	$78.1	$80.1	$85.3
Average	$77.5	$81.5	$81.3	$88.0
% Above/(Below)	-4.6%	-7.4%		

1/ NIPSCO Data effective April 1, 2008
2/ Reflects the median or 50th percentile of the market.

Petitioner's Exhibit RDC-5
Northern Indiana Public Service Company
Cause No. 43526

NCS Base Salaries & Total Compensation

Position	1/ NCS Annual Base Salary (000's)	1/ NCS Annual Total Cash Comp (000's)	General Industry Annual Base Salary 2/ (000's)	General Industry Annual Total Cash Comp 2/ (000's)
Audit Manager	$100.7	$106.9	$101.4	$109.8
Sr Auditor	$82.0	$86.8	$72.8	$76.3
Auditor 2	$70.0	$72.4	$58.9	$61.2
Financial Analyst 3	$69.7	$73.6	$74.2	$77.8
Lead Financial Analyst	$73.1	$76.8	$85.3	$90.1
Senior HR Consultant	$83.4	$88.1	$92.8	$100.8
Analyst Programmer	$55.0	$57.7	$66.4	$69.1
Average	$66.7	$70.3	$69.0	$73.1
% Above/(Below)	-3.2%	-3.9%		

Notes:
1/ NiSource Corporate Services (NCS) data effective April 1, 2008
2/ Reflects the median or 50th percentile of the market.

Petitioner's Exhibit RDC-6
Northern Indiana Public Service Company
Cause No. 43526

NIPSCO

Merit Increase Comparison

	No. of Companies Surveyed	Actual 2007 % Merit Increase	Projected 2008 % Merit Increase
Hewitt Associates 1/			
National			
Exempt	818	3.6%	3.6%
Non-Exempt Salaried	646	3.5%	3.6%
Non-Exempt Nonunion Hourly	520	3.5%	3.5%
Utilities			
Exempt	46	3.6%	3.6%
Non-Exempt Salaried	38	3.6%	3.6%
Non-Exempt Nonunion Hourly	31	3.5%	3.6%
*Midwest Region**			
Exempt	163	3.5%	3.6%
Non-Exempt	118	3.5%	3.6%
NIPSCO (Performance Awards)			
Exempt		3.0%	3.25%
Non-Exempt Nonunion Hourly		2.5%	3.25%

Notes:
1/ Source: 2007/2008 U.S. Salary Increase Survey

* Midwest Region consists of: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, Ohio, Wisconsin

AGING WORKFORCE COST SUMMARY WORKSHEET: 2008-2012

DEPARTMENT:	2008	2009	2010	2011	2012	TOTAL
DISTRIB, TRANS MTCE & FIELD SERV, AND CONSTRUCTION	$1,011,122	$1,196,806	$1,321,953	$493,042	$374,253	**$4,397,176**
ELECTRIC GENERATION	$712,369	$3,732,363	$2,872,768	$2,288,596	$1,740,614	**$11,346,709**
ELECTRIC TRANSMISSION	-	$321,720	$1,184,678	-	-	**$1,506,398**
GENERATION DISPATCH	-	-	$672,216	-	-	**$672,216**
TRADING & ENERGY MGMT	-	-	$400,673	-	-	**$400,673**
CUSTOMER SERVICE CENTER	$308,212	$271,447	$236,721	$254,082	$232,400	**$1,302,862**
TOTALS:	**$2,031,703**	**$5,522,336**	**$6,689,011**	**$3,035,720**	**$2,347,267**	**$19,626,036**

DISTRIB, TRANS MTCE & FIELD SERV, AND CONSTRUCTION - 2008							
	Planned Replacements	Payroll	Incentive	Benefits	Opns/Constr Allocator	Elect/Gas Allocator	Total
PHYSICAL UNION:							
Job Title:							
Apprentice Lineman - Incremental	12.1	$62,149	$1,864	1.2997	0.323	1.0	$322,782
App Sub Electrician - Incremental	3.8	$55,342	$1,660	1.2997	0.838	1.0	$234,196
Apprentice Meterman - Incremental	2.0	$54,225	$1,627	1.2997	0.983	1.0	$141,698
Dispatcher Operator - Incremental	1.75	$56,313	$1,689	1.2997	1.0	1.0	$131,040
Subtotals	19.65						$829,716
MANAGEMENT:							
Job Title:							
Supervisor - Trans (1 @ 3 mo in '07)	2	$74,000	$3,700	1.2997	0.702	1.0	$124,121
Supervisor - Distribution (Incr)	1.75	$74,000	$3,700	1.2997	0.4	0.5	$34,957
Eng - Trans (1 @ 2.5 mo in '07)	1	$53,000	$2,120	1.2997	0.388	1.0	$21,241
Engineer - Distribution (Incremental)	0.25	$53,000	$2,120	1.2997	0.101	0.606	$1,086
Subtotals	5						$181,406
TOTALS	**24.65**						**$1,011,122**

DISTRIB, TRANS MTCE & FIELD SERV, AND CONSTRUCTION - 2009							
	Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Opns/Constr Allocator**	**Elect/Gas Allocator**	**Total**
PHYSICAL UNION:							
Job Title:							
Apprentice Lineman - Incremental	10.1	$63,773	$1,913	1.2997	0.323	1.0	$276,467
App Sub Electrician - Incremental	4.0	$56,784	$1,704	1.2997	0.838	1.0	$252,944
Apprentice Meterman - Incremental	3.5	$55,630	$1,669	1.2997	0.983	1.0	$254,393
Dispatcher Operator - Incremental	0						$0
Subtotals	17.6						$783,804
MANAGEMENT:							
Job Title:							
Supervisor - Trans (1 @ 3 mo in '07)	4	$74,000	$3,700	1.2997	0.702	1.0	$264,350
Supervisor - Distribution (Incr)	3.75	$74,000	$3,700	1.2997	0.4	0.5	$74,908
Eng - Trans (1 @ 2.5 mo in '07)	2	$53,000	$2,120	1.2997	0.388	1.0	$48,755
Engineer - Distribution (Incremental)	5.75	$53,000	$2,120	1.2997	0.101	0.606	$24,989
Subtotals	15.5						$413,002
TOTALS	**33.1**						**$1,196,806**

DISTRIB, TRANS MTCE & FIELD SERV, AND CONSTRUCTION - 2010								
		Planned Replacements	Payroll	Incentive	Benefits	Opns/Constr Allocator	Elect/Gas Allocator	Total
PHYSICAL UNION:								
Job Title:								
Apprentice Lineman - Incremental		5.6	$63,773	$1,913	1.2997	0.323	1.0	$153,289
App Sub Electrician - Incremental		1.3	$56,784	$1,704	1.2997	0.838	1.0	$82,207
Apprentice Meterman - Incremental		4.0	$55,630	$1,669	1.2997	0.983	1.0	$290,734
Dispatcher Operator - Incremental		1.25	$57,788	$1,734	1.2997	1.0	1.0	$96,050
	Subtotals	12.15						$622,280
MANAGEMENT:								
Job Title:								
Supervisor - Trans (1 @ 3 mo in '07)		7	$74,000	$3,700	1.2997	0.702	1.0	$474,692
Supervisor - Distribution (Incr)		1.5	$74,000	$3,700	1.2997	0.4	0.5	$29,963
Eng - Trans (1 @ 2.5 mo in '07)		7	$53,000	$2,120	1.2997	0.388	1.0	$186,326
Engineer - Distribution (Incremental)		2	$53,000	$2,120	1.2997	0.101	0.606	$8,692
	Subtotals	17.5						$699,673
	TOTALS	**29.65**						**$1,321,953**

DISTRIB, TRANS MTCE & FIELD SERV, AND CONSTRUCTION - 2011							
	Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Opns/Constr Allocator**	**Elect/Gas Allocator**	**Total**
PHYSICAL UNION:							
Job Title:							
Apprentice Lineman - Incremental	1.1	$63,773	$1,913	1.2997	0.323	1.0	$30,110
App Sub Electrician - Incremental	0.8	$56,784	$1,704	1.2997	0.838	1.0	$50,589
Apprentice Meterman - Incremental	3.5	$55,630	$1,669	1.2997	0.983	1.0	$254,393
Dispatcher Operator - Incremental	1.75	$56,313	$1,689	1.2997	1.0	1.0	$131,040
Subtotals	7.15						$466,131
MANAGEMENT:							
Job Title:							
Supervisor - Trans (1 @ 3 mo in '07)	0	$74,000	$3,700	1.2997	0.702	1.0	($16,107)
Supervisor - Distribution (Incr)	2.25	$74,000	$3,700	1.2997	0.4	0.5	$44,945
Eng - Trans (1 @ 2.5 mo in '07)	0	$53,000	$2,120	1.2997	0.388	1.0	($6,273)
Engineer - Distribution (Incremental)	1	$53,000	$2,120	1.2997	0.101	0.606	$4,346
Subtotals	3.25						$26,911
TOTALS	**10.4**						**$493,042**

Petitioner's Exhibit RDC-7
Northern Indiana Public Service Company
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	Planned Replacements	Payroll	Incentive	Benefits	Opns/Constr Allocator	Elect/Gas Allocator	Total
DISTRIB, TRANS MTCE & FIELD SERV, AND CONSTRUCTION - 2012							
PHYSICAL UNION:							
Job Title:							
Apprentice Lineman - Incremental	0.6	$64,018	$1,921	1.2997	0.323	1.0	$16,487
App Sub Electrician - Incremental	0.5	$57,002	$1,710	1.2997	0.838	1.0	$31,740
Apprentice Meterman - Incremental	0.5	$55,844	$1,675	1.2997	0.983	1.0	$36,482
Dispatcher Operator - Incremental	1.75	$56,313	$1,689	1.2997	1.0	1.0	$131,040
Subtotals	3.35						$215,748
MANAGEMENT:							
Job Title:							
Supervisor - Trans (1 @ 3 mo in '07)	1	$74,000	$3,700	1.2997	0.702	1.0	$54,007
Supervisor - Distribution (Incr)	1.25	$74,000	$3,700	1.2997	0.4	0.5	$24,969
Eng - Trans (1 @ 2.5 mo in '07)	3	$53,000	$2,120	1.2997	0.388	1.0	$76,269
Engineer - Distribution (Incremental)	0.75	$53,000	$2,120	1.2997	0.101	0.606	$3,259
Subtotals	6						$158,505
TOTALS	**9.35**						**$374,253**

ELECTRIC GENERATION - 2008						
	Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Opns/Constr Allocator**	**Total**
PHYSICAL UNION:						
Job Title:						
Apprentice Station Mechanic	5	$53,539	$1,606	1.2997	0.876	$77,954
Apprentice Instrument Tech	4	$53,810	$1,614	1.2997	0.920	$65,827
Apprentice Chemical Tech	4	$54,704	$1,641	1.2997	0.984	$71,576
Relief Operator Progression	7	$60,174	$1,805	1.2997	1.0	$140,024
Subtotals	20					$355,381
MANAGEMENT:						
Job Title:						
Supervisor	14	$76,000	$3,800	1.2997	0.8	$287,216
Engineer	6	$80,000	$3,200	1.2997	0.434	$69,772
Subtotals	20					$356,988
TOTALS	**40**					**$712,369**

Petitioner's Exhibit RDC-7
Northern Indiana Public Service Company
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ELECTRIC GENERATION - 2009

		Planned Replacements	Payroll	Incentive	Benefits	Opns/Constr Allocator	Total
PHYSICAL UNION:							
Job Title:							
Apprentice Station Mechanic		5	$55,661	$1,670	1.2997	0.876	$324,173
Apprentice Instrument Tech		3	$55,962	$1,679	1.2997	0.920	$205,380
Apprentice Chemical Tech		4	$56,826	$1,705	1.2997	0.984	$297,408
Relief Operator Progression		20	$65,225	$1,957	1.2997	1.0	$1,734,603
	Subtotals	32					$2,561,564
MANAGEMENT:							
Job Title:							
Supervisor		12	$76,000	$3,800	1.2997	0.8	$984,741
Engineer		4	$80,000	$3,200	1.2997	0.434	$186,058
	Subtotals	16					$1,170,799
	TOTALS	**48**					**$3,732,363**

ELECTRIC GENERATION - 2010						
	Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Opns/Constr Allocator**	**Total**
PHYSICAL UNION:						
Job Title:						
Apprentice Station Mechanic	5	$55,661	$1,670	1.2997	0.876	$324,173
Apprentice Instrument Tech	3	$55,962	$1,679	1.2997	0.920	$205,380
Apprentice Chemical Tech	4	$56,826	$1,705	1.2997	0.984	$297,408
Relief Operator Progression	14	$65,225	$1,957	1.2997	1.0	$1,214,222
Subtotals	26					$2,041,184
MANAGEMENT:						
Job Title:						
Supervisor	9	$76,000	$3,800	1.2997	0.8	$738,556
Engineer	2	$80,000	$3,200	1.2997	0.434	$93,029
Subtotals	11					$831,585
TOTALS	**37**					**$2,872,768**

ELECTRIC GENERATION - 2011

	Planned Replacements	Payroll	Incentive	Benefits	Opns/Constr Allocator	Total
PHYSICAL UNION:						
Job Title:						
Apprentice Station Mechanic	5	$55,661	$1,670	1.2997	0.876	$324,173
Apprentice Instrument Tech	2	$55,962	$1,679	1.2997	0.920	$136,920
Apprentice Chemical Tech	4	$56,826	$1,705	1.2997	0.984	$297,408
Relief Operator Progression	9	$65,225	$1,957	1.2997	1.0	$780,571
Subtotals	20					$1,539,073
MANAGEMENT:						
Job Title:						
Supervisor	8	$76,000	$3,800	1.2997	0.8	$656,494
Engineer	2	$80,000	$3,200	1.2997	0.434	$93,029
Subtotals	10					$749,523
TOTALS	**30**					**$2,288,596**

ELECTRIC GENERATION - 2012							
		Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Opns/Constr Allocator**	**Total**
PHYSICAL UNION:							
Job Title:							
Apprentice Station Mechanic		5	$55,875	$1,676	1.2997	0.876	$325,420
Apprentice Instrument Tech		0					$0
Apprentice Chemical Tech		4	$56,826	$1,705	1.2997	0.984	$297,408
Relief Operator Progression		8	$65,476	$1,964	1.2997	1.0	$696,510
	Subtotals	17					$1,319,338
MANAGEMENT:							
Job Title:							
Supervisor		4	$76,000	$3,800	1.2997	0.8	$328,247
Engineer		2	$80,000	$3,200	1.2997	0.434	$93,029
	Subtotals	6					$421,276
	TOTALS	**23**					**$1,740,614**

Petitioner's Exhibit RDC-7
Northern Indiana Public Service Company
Cause No. 43526

ELECTRIC TRANSMISSION - 2009

	Planned Replacements	Payroll	Incentive	Benefits	Other	Opns/Constr Allocator	Total
MANAGEMENT:							
Job Title:							
Operations							
Transmission System Supv	0						$0
Transmission Resource Eng	0						$0
Planning							
Planning Engineer	0						$0
Protection Engineer	0						$0
Engineering							
Support Specialist	0						$0
FERC/NERC Compl & Training							
Compliance Engineer	2	$86,653	$3,466	1.2997	$8,000	1.0	$190,133
Systems Engineer	1	$106,080	$4,243	1.2997	$25,000	1.0	$131,587
EMS & Computer Applications							
Applications Engineer	0						$0
TOTALS	**3**						**$321,720**

Petitioner's Exhibit RDC-7
Northern Indiana Public Service Company
Cause No. 43526

ELECTRIC TRANSMISSION - 2010							
	Planned Replacements	Payroll	Incentive	Benefits	Other	Opns/Constr Allocator	Total
MANAGEMENT:							
Job Title:							
Operations							
Transmission System Supv	3	$81,432	$3,257	1.2997	$5,110	1.0	$342,613
Transmission Resource Eng	1	$76,170	$3,047	1.2997	$21,510	1.0	$123,554
Planning							
Planning Engineer	1	$80,059	$3,202	1.2997	$9,700	1.0	$116,955
Protection Engineer	3	$77,293	$3,092	1.2997	$19,400	1.0	$368,847
Engineering							
Support Specialist	1	$59,134	$2,365	1.2997	$0	0.331	$26,254
FERC/NERC Compl & Training							
Compliance Engineer	2	$86,653	$3,466	1.2997	$0	1.0	$58,044
Systems Engineer	1	$106,080	$4,243	1.2997	$0	1.0	$35,529
EMS & Computer Applications							
Applications Engineer	1	$76,794	$3,072	1.2997	$10,000	1.0	$112,880
TOTALS	**13**						**$1,184,678**

GENERATION DISPATCH - 2010						
	Planned Replacements	Payroll	Incentive	Benefits	Other	Total
MANAGEMENT:						
Job Title:						
Operations Analysis Engineer	2	$82,909	$3,316	1.2997	$2,310	$226,766
Energy Resources Engineer	1	$89,045	$3,562	1.2997	$2,310	$121,603
Gen System Supervisor	2	$77,958	$3,118	1.2997	$2,310	$213,502
Lead Analyst	1	$80,642	$3,226	1.2997	$2,310	$110,346
TOTALS	**6**					**$672,216**

TRADING & ENERGY MANAGEMENT - 2010									
				Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Other**	**Total**
MANAGEMENT:									
Job Title:									
Energy Resource Trader				3	$97,968	$3,919	1.2997	$2,310	$400,673
			TOTALS	3					**$400,673**

CUSTOMER SERVICE CENTER - 2008							
	Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Opns/Constr Allocator**	**Electric/Gas Allocator**	**Total**
CLERICAL UNION:							
Job Title:							
Part-Time CSR's (11 in '07)	27	$37,840	$0	1.147	1.0	0.3899	$276,871
MANAGEMENT:							
Job Title:							
Trainer	1	$60,000	$2,400	1.2997	1.0	0.3899	$31,341
Team Leader	0						$0
Administative Assistant	0						$0
TOTALS	**28**						**$308,212**

Petitioner's Exhibit RDC-7
Northern Indiana Public Service Company
Cause No. 43526

CUSTOMER SERVICE CENTER - 2009

	Planned Replacements	Payroll	Incentive	Benefits	Opns/Constr Allocator	Electric/Gas Allocator	Total
CLERICAL UNION:							
Job Title:							
Part-Time CSR's (11 in '07)	26	$38,829	$0	1.147	1.0	0.3899	$271,447
MANAGEMENT:							
Job Title:							
Trainer	0						$0
Team Leader	0						$0
Administative Assistant	0						$0
TOTALS	**26**						**$271,447**

Petitioner's Exhibit RDC-7
Northern Indiana Public Service Company
Cause No. 43526

CUSTOMER SERVICE CENTER - 2010							
	Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Opns/Constr Allocator**	**Electric/Gas Allocator**	**Total**
CLERICAL UNION:							
Job Title:							
Part-Time CSR's (11 in '07)	21	$38,829	$0	1.147	1.0	0.3899	$184,622
MANAGEMENT:							
Job Title:							
Trainer	0						$0
Team Leader	1	$55,000	$2,750	1.2997	1.0	0.3899	$28,944
Administative Assistant	1	$45,000	$900	1.2997	1.0	0.3899	$23,155
TOTALS	**23**						**$236,721**

Petitioner's Exhibit RDC-7
Northern Indiana Public Service Company
Cause No. 43526

CUSTOMER SERVICE CENTER - 2011

	Planned Replacements	Payroll	Incentive	Benefits	Opns/Constr Allocator	Electric/Gas Allocator	Total
CLERICAL UNION:							
Job Title:							
Part-Time CSR's (11 in '07)	25	$38,829	$0	1.147	1.0	0.3899	$254,082
MANAGEMENT:							
Job Title:							
Trainer	0						$0
Team Leader	0						$0
Administative Assistant	0						$0
TOTALS	**25**						**$254,082**

CUSTOMER SERVICE CENTER - 2012							
	Planned Replacements	**Payroll**	**Incentive**	**Benefits**	**Opns/Constr Allocator**	**Electric/Gas Allocator**	**Total**
CLERICAL UNION:							
Job Title:							
Part-Time CSR's (11 in '07)	22	$38,978	$0	1.147	1.0	0.3899	$203,457
MANAGEMENT:							
Job Title:							
Trainer	0						$0
Team Leader	1	$55,000	$2,750	1.2997	1.0	0.3899	$28,944
Administative Assistant	0						$0
TOTALS	**23**						**$232,400**

Petitioner's Exhibit SMT-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

SUSANNE M. TAYLOR

CONTROLLER, NISOURCE CORPORATE SERVICES COMPANY

SPONSORING PETITIONER'S EXHIBITS SMT-2 THROUGH SMT-6

VERIFIED DIRECT TESTIMONY OF SUSANNE M. TAYLOR

Q1. Please state your name and business address.

A1. My name is Susanne M. Taylor. My business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q2. By whom are you employed and in what capacity?

A2. I am employed by NiSource Corporate Services Company ("NCS") as Controller. I am submitting this testimony on behalf of Northern Indiana Public Service Company ("NIPSCO" or the "Company").

Q3. Please briefly describe your professional experience.

A3. I was employed at KPMG Peat Marwick from August 1991 through June 1993 where I held various accounting positions ranging from Staff Accountant to In-Charge Accountant. In July 1993, I was hired by the Columbia Energy Group's Service Corporation as a Staff Auditor. From May 1994 to May 2000, I held various analyst positions in the Regulatory Department. In June 2000, I took a position as Lead Financial Analyst in the Financial Planning Support Department. I was promoted to Manager of Corporate Accounting following the merger between Columbia Energy Group ("Columbia") and NiSource Inc. ("NiSource") on November 1, 2000. In April 2005, I was promoted to my current position as Controller of NCS.

Q4. What are your responsibilities as Controller?

A4. As Controller, my principal responsibilities include overseeing the general books and records of NCS. In carrying out these duties, I am responsible for a number of activities, including:

(1) Maintaining the accounting system that identifies the costs for services that are subsequently billed to the operating companies within the NiSource corporate organization ("NiSource affiliates" or "affiliates");

(2) Developing accounting data, providing testimony, and responding to requests from regulatory and legislative bodies with regard to NCS billing on behalf of NiSource affiliates; and

(3) Providing accounting and financial planning services for other affiliate companies.

Q5. Please state your educational background.

A5. I received a Bachelor of Science degree in Accounting in 1991 from Ohio University, Athens, Ohio.

Q6. What are your professional credentials?

A6. I am a Certified Public Accountant and am currently a member of the Ohio Society of Certified Public Accountants ("OSCPA"). I regularly attend accounting and accounting-related seminars sponsored by various organizations including the American Gas Association, OSCPA and Deloitte & Touche.

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is two fold. First, I provide background about NCS and the role it serves within NiSource. Second, I support the annualized level of fixed, known and measurable NCS charges applicable to NIPSCO. In supporting that annualized expense level, I provide information pertaining to the types of costs that have been allocated to NIPSCO and the mechanism for determining the appropriate allocation of each type of cost.

I. THE RELATIONSHIP BETWEEN NCS AND NIPSCO.

Q8. Please explain the structure and role of NCS.

A8. NCS is a subsidiary of NiSource and an affiliate of NIPSCO within the NiSource corporate organization. NCS provides a range of services to the individual operating companies within NiSource, including NIPSCO, and also coordinates the allocation and billing of charges to the NiSource operating companies for services provided by both NCS directly and by third-party vendors.

Q9. As Controller, do you oversee the allocation and billing of affiliate charges by NCS?

A9. Yes, my area is responsible for reviewing general overall charges billed to each of the NiSource affiliates by NCS. I am also responsible for the accounting system that tracks and identifies the costs for services that are subsequently billed to NiSource affiliates, including NIPSCO.

Q10. Is NCS responsible for assessing the split between costs appropriately attributable to NIPSCO's gas and electric operations?

A10. No. That function is performed within NIPSCO. NIPSCO Witness Mitchell Hershberger explains how that split is performed.

Q11. Please identify the individual corporate affiliates for which NCS performed services during the test period.

A11. Petitioner's Exhibit SMT-2 lists all affiliates for which NCS performed services during the test period.

Q12. How are costs billed to affiliates?

A12. There are two types of billings made to affiliates, including NIPSCO: (1) contract billing; and (2) convenience billing. Contract billings are identified by job order and represent NCS labor and expenses billed to the respective affiliate. Contract billed charges may be direct (billed directly to a single affiliate) or allocated (split between or among several affiliates), depending upon the nature of the expense.

Convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate is billed on a monthly basis for its proportional share of the payments made in that respective month. As the name implies, convenience billing is intended as a convenience to vendors because it eliminates the need for a separate invoice to be generated for each affiliate entity receiving the same services. Therefore, NCS makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliate.

Q13. Is contract billing rendered pursuant to an executed contract?

A13. Yes, NCS has executed an individual Service Agreement with each affiliate, which designates the type of services to be performed and the method of calculating the charges for those services. Services rendered under the Service Agreement are provided at cost, including interest charges for financing. The Service Agreement is updated from time to time so that all affiliates that receive service from NCS are subject to the same Service Agreement, with one exception.[1] A copy of the most recent Service Agreement between NCS and NIPSCO was submitted to this Commission on November 21, 2007 (the "2007 Agreement"), replacing the predecessor Service Agreement that was submitted to the Commission on March 31, 2005 (the "2005 Agreement"). A copy of the 2007 Agreement is attached hereto as <u>Petitioner's Exhibit SMT-4</u> and a copy of the 2005 Agreement is attached hereto as <u>Petitioner's Exhibit SMT-5</u>. The revision in 2007 updated Appendix A of the Service Agreement that provides a description of the Service Categories offered by NCS to the NiSource operating companies. The revisions to Appendix A were made because the Virginia State Corporation Commission requested that NCS modify its Service Agreement with Columbia Gas of Virginia to detail the specific services included in the IBM outsourcing agreement whether or not the services were already included in existing Service Categories or covered under the Miscellaneous Service Category. Since NCS utilizes the same Service Agreement among all affiliates, all Service Agreements were modified to be consistent across all companies.

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[1] The Virginia PUC recently required inclusion of a Virginia-specific service category that is not included in the Service Agreements for non-Virginia affiliates.

Q14. Were there changes to the way costs were billed to NIPSCO under the 2005 Agreement and the 2007 Agreement?

A14. No. Costs under the two agreements were handled and billed by NCS in the same way. As I described earlier, the changes between the 2005 Agreement and the 2007 Agreement modified the description of the Service Categories contained in Appendix A, but did not modify the way individual expenses were billed or allocated.

Q15. Have you prepared a summary of the services and charges provided to NIPSCO by NCS under the Service Agreement?

A15. Yes, a schedule titled "NiSource Corporate Services Company Test Year Expenses" is attached hereto as Petitioner's Exhibit SMT-3. Petitioner's Exhibit SMT-3 displays charges billed to NIPSCO on a total company basis by service category for calendar year 2007, the test year in this proceeding. As shown, NCS billed NIPSCO a total of $73,988,195 during the test year, on an unadjusted basis. This amount includes billings for both NIPSCO's gas and electric operations. The adjustments to these test year results described later in my testimony have been made to this amount resulting in a proforma level of NCS charges to NIPSCO. Mr. Hershberger explains in his direct testimony how the NCS contract billings, including the adjustments described later in my testimony, have been allocated between NIPSCO's electric and gas operations. The types of services provided by NCS to affiliates like NIPSCO under each service category are briefly described below.

Q16. What type of services were contract billed to NIPSCO during the test year?

A16. Based on the total charges by Service Category as shown on Petitioner's Exhibit SMT-3, the largest dollar categories of services provided to NIPSCO during the test year were: Information Technology; Operations Support and Planning; Legal; Rate; Employee; Customer Billing, Collection and Contact; Accounting and Statistical; Office Space; Corporate; and Purchasing, Storage and Disposition. The remaining categories of service each made up less than three percent (3%) of the total test year allocated costs.

Q17. What functions are provided by Information Technology services?

A17. Information Technology services generally fall into one of the following categories: application development and maintenance; network support; mainframe support; server support; and end-user services.

These functional areas provide application development, modifications, upgrades, maintenance, and ongoing production support for NiSource's portfolio of systems and software that are used by multiple operating companies, including NIPSCO. Specific applications used by NIPSCO include: general ledger; accounts payable; plant accounting; employee information; payroll; and a variety of other mechanized systems.

Information Technology is responsible for providing daily operational control, monitoring, data access security, disaster recovery planning, and technical research. This support includes 24 hours per day, 365 days per year support services, problem resolution, development, installation and maintenance of all hardware and software functions needed to operate and control a large scale network computing system.

Information Technology is also responsible for ensuring that new functions added to the environment are compatible with the overall structure of the system and will deliver and operate as required. In addition, ongoing evaluation and monitoring of the network computing environment is provided to ensure efficient use of the hardware and timely upgrades to meet the demands of the corporation. This includes reviewing the resources needed for all new applications or major changes to existing applications.

Q18. What functions are provided by Operations Support and Planning services?

A18. Operations Support and Planning services manage the electric field operations, distribution engineering, and transmission and distribution construction. These services cover regulatory compliance including compliance with environmental, health and safety legislation, as well as environmental project management.

Q19. What functions are provided by Legal services?

A19. Legal services includes services provided by attorneys employed by NCS and fees billed to NCS by outside counsel. Legal services fall into two broad categories. The first category encompasses counsel and representation provided directly to all affiliates. These include matters relating to employee benefits and human resources, environmental, financing, general corporate and securities matters, and other matters, such as regulatory issues and litigation. The second category encompasses legal support provided to the various NCS departments that in turn provide services to affiliates, as well as services provided directly to affiliates upon request. Included among the NCS categories to which day-to-day representation is provided are Accounting, Tax, Employee, Rate, Insurance, Information Technology, and Information Services. These specific services include providing advice, recommendations and analyses in the form of legal opinions and memoranda of law, negotiation, drafting and review of agreements, contracts and other documents, analyses of legal implications of actions taken by the SEC, FERC and other state and federal agencies, problem identification and practice of preventive law, and direction and monitoring of outside legal services.

Q20. What functions are provided by Rate services?

A20. Rate services provides assistance in all regulatory matters including design and preparation of schedules and tariffs, analysis of rate filings, and preparation and presentation of testimony and exhibits to regulatory authorities.

Q21. What functions are provided by Employee services?

A21. Employee services provides both consultative and administrative services to NIPSCO. These services relate to benefits and compensation design and administration, interpretation of new or pending human resources-related legislation, policy development, temporary labor matters, and coordination of human resources activities.

Q22. What functions are provided by Customer Billing, Collection and Contact services?

A22. Services related to Customer Billing include calculating, posting, printing, inserting and mailing customer bills, notices, inserts and similar mailings, as well as bill exception and back office processing. Services related to Collection include cash processing, revenue recovery, and preparation and management of accounts receivable aging reports. Contact services are not provided to NIPSCO by NCS, as these functions are handled by NIPSCO internally.

Q23. What functions are provided by Accounting and Statistical services?

A23. Accounting and Statistical services ("Accounting") provides functions including financial, plant, and regulatory accounting. Accounting is also responsible for maintenance of books and records, accounts receivable, and reconciliations. Accounting's duties include developing, analyzing and interpreting financial statements, preparing data for board of directors' reports, regulatory reports, operating statistics and other internal and external financial reports. Accounting also ensures compliance with Generally Accepted Accounting Principles by reviewing discussion memos, exposure drafts, financial accounting standards, and interpretations issued by the Financial Accounting Standards Board ("FASB"). Accounting also reviews accounting directives from the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions to ensure compliance with regulatory reporting requirements.

Accounting also includes a Consolidation Accounting group, which provides guidance to NIPSCO and other NiSource affiliates, in the setting of accounting policies, procedure development and maintaining a uniform system of accounts. The Consolidation Accounting group reviews new accounting releases from the FASB, the Securities and Exchange Commission ("SEC"), FERC, etc., provides interpretation guidance and assists in implementation. This group also prepares NiSource's financial statements, such as the

Annual and Quarterly Report to Stockholders, Form 10-K and 10-Q and various other consolidated financial statements required for financial and regulatory filings.

Q24. What functions are provided by Office Space services?

A24. Office Space services is responsible for facility management activities, including maintaining and repairing company facilities (including electrical, mechanical, heating and cooling systems), operating and maintaining the buildings, and providing a safe and productive working environment for employees.

Q25. What primary functions are provided by Corporate services?

A25. Corporate services includes governance of outsourced contracts, proceedings with regulatory bodies, preparation of board resolutions and minutes, filing of legal documents, and other corporate development functions.

Q26. What major functions are provided by Purchasing, Storage and Disposition services?

A26. The major functions provided by Purchasing, Storage and Disposition services are the evaluation, implementation, negotiation, standardization and consolidation of equipment, materials, supplies and vendor relations.

II. COST ASSIGNMENT TO NIPSCO BY NCS.

Q27. How does NCS determine charges applicable to NIPSCO?

A27. NCS was regulated by the SEC under the Public Utility Holding Company Act of 1935 until February 8, 2006, when the Public Utility Holding Company Act of 2005 ("PUHCA 2005") was enacted. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the SEC to FERC. Pursuant to FERC Order No. 684 issued October 19, 2006, centralized service companies (like NCS) must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with PUHCA 2005 and FERC, NCS uses a job order system to collect costs that are applicable and billable to affiliates, including NIPSCO. A job order assigns a 10-digit number to the project or projects involved and details how expenses are to be charged for the project. This is the same job order system used by NCS for many years. Specific projects and/or departmental labor are assigned a job order or a new job order is created. Costs are directly charged to a particular affiliate whenever possible. Some job orders necessarily involve more than one affiliate, and in that case, the job order details how expenses are allocated among the participating affiliates.

Q28. Please explain how costs assigned to a particular job order are allocated.

A28. Allocations among affiliates are made only if it is impractical or inappropriate to charge an affiliate directly. Whenever a new job order is created, a decision is made cooperatively by the departmental head working with the operating company and NCS personnel about how costs assigned to that job order will be allocated among participating affiliates. A Basis of Allocation or a direct company code is assigned to the job order based on this direction, and then costs are billed following this specified information. Unless a change occurs in the identity of the affiliates participating in a specific job order, costs that are assigned to the job order will be consistently billed by

NCS to its affiliates from that point forward because the job order Bases of Allocation remain the same over time.

Q29. Please describe the controls in place to ensure that an affiliate is consistently and appropriately billed for a specific job order.

A29. The job orders are maintained by the NCS Accounting Department; and therefore, only a few individuals within NCS Accounting can create or modify job orders. Each job order can be set up with only one Basis of Allocation, and in many cases, only one specific allocation code or direct company billing is set up for a particular job order, depending on what affiliate(s) benefit from the services. If an individual would attempt to use a different Basis of Allocation with a job order that was not selected at inception, the related accounting systems would prompt an immediate error and not allow data to be input at the time of entry.

Q30. What are the Bases of Allocation?

A30. NCS allocates costs for a particular job order in accordance with the following Bases of Allocation that have been previously approved by the SEC and filed annually with the FERC:

<u>BASIS 1</u> - Gross Fixed Assets and Total Operating Expenses

<u>BASIS 2</u> - Gross Fixed Assets

<u>BASIS 7</u> - Gross Depreciable Property & Total Operating Expenses

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BASIS 8 - Gross Depreciable Property

BASIS 9 - Number of Automotive Units (Owned and Leased)

BASIS 10 - Number of Retail Customers

BASIS 11 - Number of Regular Employees

BASIS 13 - Fixed Allocation

BASIS 14 - Number of Transportation Customers

BASIS 15 - Number of Commercial Customers (not used for NIPSCO)

BASIS 16 - Number of Residential Customers (not used for NIPSCO)

BASIS 17 - Number of High Pressure Customers (not used for NIPSCO)

BASIS 20 - Direct Costs

A description of the each Basis of Allocation is included in Petitioner's Exhibit SMT-4 (Exhibit A to Appendix A).

Q31. Are charges for services rendered to NIPSCO billed at cost?

A31. Yes, in accordance with the 2007 Agreement (Section 2.2), all services are provided at cost.

Q32. Please explain each affiliate's rights regarding bills issued by NCS.

A32. In accordance with the 2007 Agreement (Section 2.3), affiliates have the right to review and challenge any particular item for which they are billed. Mr. Hershberger addresses how NIPSCO reviews bills received from NCS.

III. ADJUSTMENTS TO TEST YEAR NCS ALLOCATION TO NIPSCO.

Q33. Have you prepared an exhibit that documents the adjustments to test year NCS allocations?

A33. Yes. Petitioner's Exhibit SMT-6 shows the calculation of the adjustments to test year expense.

Q34. Please explain the pro forma adjustments made to the test year NCS allocations to NIPSCO.

A34. Two types of adjustments were made to test year NCS allocations to NIPSCO. The first type of adjustments were made to eliminate one time, non-recurring charges and are shown in Col. B, Col. C and Col. D of Petitioner's Exhibit SMT-6. The one-time, non-recurring charges are broken down into three subcategories (1) IBM one-time costs (shown in Col. B of Petitioner's Exhibit SMT-6), (2) other one-time costs (shown in Col. C of Petitioner's Exhibit SMT-6), and (3) an incentive compensation adjustment (shown in Col. D of Petitioner's Exhibit SMT-6). All charges in these three subcategories were billed to NIPSCO during the test year on a total company basis and have been adjusted out as non-recurring. The second type of adjustments were made to reflect ongoing NCS expense levels and are shown in Col. F, Col. G and Col. H of Petitioner's Exhibit SMT-6.

Q35. Please describe the IBM-related one time costs excluded from test year expenses.

A35. The IBM-related one-time costs (shown in Col. B of Petitioner's Exhibit SMT-6) of $3,961,081 relate to items such as transition, system transformation, settlement, benefit restructuring adjustment, and consulting costs incurred in restructuring the IBM agreement, and have been removed from the test year. In December 2007, NCS restructured its outsourcing arrangement with IBM. In addition, on June 1, 2007, certain Finance and Accounting functions were transitioned from IBM back to NCS, including general accounting, fixed asset accounting and budgeting. These non-recurring costs of $363,118 are included in the $3,961,081 noted above. In addition, Work Management System ("WMS") costs in the amount of $3,071,636 (included above) were deemed to be one-time in nature. WMS costs relate to supplemental contract costs paid to IBM for the upfront design assessment and configuration of the new Work Management/Geographical Information System. NIPSCO Witness Timothy A. Dehring provides further details concerning the WMS.

Q36. Please describe the other one-time costs excluded from test year expenses.

A36. The other one-time costs (shown in Col. C of Petitioner's Exhibit SMT-6) of $990,780 relate to costs and miscellaneous adjustments billed by NCS to NIPSCO in the test year including, reimbursement from the sale of a mainframe equipment, market value adjustment of the Marble Cliff facility, building re-configuration costs, miscellaneous severance costs, and other miscellaneous invoice adjustments.

The first one time cost of $(5,867) relates to a reimbursement from the sale of a mainframe asset relating to a necessary replacement of one of the primary mainframe assets. The second one-time cost of $791,572 relates to an impairment loss recorded for a market value adjustment of the Marble Cliff, Ohio building which is currently in the process of being sold. The Marble Cliff facility is owned by NCS and was primarily occupied by the Information Technology department which benefited all NiSource affiliates. The adjustment reflected an assessment of the market value versus the book value of the building, plus any other costs related to the facility including property taxes. The third one-time cost of $21,767 relates to building re-configuration costs relating to the selling of the building that formerly housed NIPSCO headquarters in October 2007. The fourth one-time cost of $75,718 relates to a miscellaneous severance cost. The last one-time cost of $107,590 relates to the review of invoice data charged to NIPSCO relating to expenses such as dues, memberships, and lobbying fees that are not appropriate for recovery in rates.

Q37. Please describe the adjustment for incentive compensation excluded from test year expenses.

A37. The incentive compensation adjustment (shown in Col. D of Petitioner's Exhibit SMT-6) of $73,466 relates to a reduction for the accrual recorded in the 2007 test year compared to the actual payout for 2007 incentive compensation.

Q38. Please describe the second type of pro forma adjustments to the test year NCS charges allocated to NIPSCO.

A38. The second type of pro forma adjustments made to the test year NCS allocations were made to reflect ongoing levels of expense. The first adjustment of $729,806 (as shown in Col. F of Petitioner's Exhibit SMT-6) relates to payroll merit increases and associated benefit increases made to reflect a three and one-quarter percent increase for NCS employees effective March 1, 2008. The second adjustment of $216,765 (as shown in Col. G of Petitioner's Exhibit SMT-6) decreases incentive compensation to reflect the anticipated lower payout level for 2008 compared to the actual payout for the test year. The third adjustment of $1,729,890 (as shown in Col. H of Petitioner's Exhibit SMT-6) reflects the increased fixed fee for the IBM Information Technology contract. That contract includes an escalation clause adjustment for calendar year 2008. The escalation adjustment is made during July of each year and was calculated at 4.05% as of June 30, 2008.

Q39. Is each of the adjustments you propose fixed in time, measurable in amount, and known to occur within twelve months following the close of the test year?

A39. Yes, they are.

Q40. Please explain the line items at the bottom of Petitioner's Exhibit SMT-6 reflecting transfers to Regulatory Asset and Capital or other Balance Sheet Accounts.

A40. The amounts shown as transfers to Regulatory Asset and to Capital or other Balance Sheet Accounts are items that were billed to NIPSCO by NCS but are related to capital projects, stores expenses, or specific balance sheet accounts that are being deferred such as rate case expense. These transfers to the Balance Sheet were identified by the

NIPSCO accounting staff and made directly on NIPSCO's books. The adjustments reflected on Petitioner's Exhibit SMT-6 are necessary to reconcile contract charges billed by NCS during the test year with the test year expenses reflected by NIPSCO for cost of service purposes.

Q41. Does this conclude your prepared direct testimony?

A41. Yes, it does.

VERIFICATION

I, Susanne M. Taylor, Controller of NiSource Service Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Susanne M. Taylor

Susanne M. Taylor

Date: August 22, 2008

NiSource Corporate Services Company

List of Associate Billing Companies

Company Name
Bay State Gas Company
CNS Microwave, Inc.
Columbia Atlantic Trading Corporation
Columbia Deep Water Services Company
Columbia Energy Group
Columbia Energy Holdings Corporation
Columbia Energy Services Corporation
Columbia Gas of Kentucky, Inc.
Columbia Gas of Maryland, Inc.
Columbia Gas of Ohio, Inc.
Columbia Gas of Pennsylvania, Inc.
Columbia Gas of Virginia, Inc.
Columbia Gas Transmission Corporation
Columbia Gulf Transmission Corporation
Columbia of Ohio Receivables Corporation
Columbia Remainder Corporation
Crossroads Pipeline Company
Energy USA, Inc.
Granite State Gas Transmission, Inc.
Kokomo Gas and Fuel Company
NI Energy Services, Inc.
NiSource Capital Markets, Inc.
NiSource Development Company, Inc.
NiSource Energy Technology, Inc.
NiSource Finance Corporation
NiSource Gas Transmission & Storage Company
NiSource Inc.
NiSource Insurance Corporation Limited
NiSource Retail Services, Inc.
Northern Indiana Fuel and Light Company, Inc.
Northern Indiana Public Service Company
Northern Utilities, Inc. - Maine
Northern Utilities, Inc. - New Hampshire
PEI Holdings, Inc.
TPC

NiSource Corporate Services Company (NCS) Test Year Expenses
December 31, 2007

	2007 NIPSCO Contract Billings
Accounting and Statistical Services	3,353,445.98
Auditing Services	900,492.94
Budget Services	854,641.99
Business Promotion Services	1,424.68
Corporate Services	2,579,750.20
Customer Billing, Collection, and Contact Services	3,441,101.35
Electronic Communications	-
Employee Services	3,508,946.05
Engineering and Research Services	631,641.69
Gas Dispatching Services	668,686.86
Information Services	1,015,905.72
Information Technology Services	29,471,840.52
Insurance Services	982,236.97
Interest, Stock and Tax	1,197,617.06
Legal Services	5,908,805.85
Office Space	2,860,819.98
Operations Support and Planning Services	7,319,824.68
Purchasing, Storage and Disposition Services	2,456,288.56
Rate Services	3,727,275.77
Tax Services	626,360.07
Transportation Services	1,667,562.86
Treasury Services	813,525.00
Grand Total	**$ 73,988,194.78**

* Interest, stock compensation and tax expense are tracked separately by NCS so that these costs can be readily idenitified and tracked for accounting purposes. Pursuant to the Service Agreement with NIPSCO, these charges represent NCS costs to maintain the service company structure.

Petitioner's Exhibit SMT-4
Northern Indiana Public Service Company
Cause No. 43526

Service Agreement

BETWEEN

NISOURCE CORPORATE SERVICES COMPANY

AND

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Dated November 1, 2007

(To Take Effect Pursuant to Article 3 Hereof)

SERVICE AGREEMENT

This SERVICE AGREEMENT (the "Service Agreement" or "Agreement") is made and entered into this 1st day of November, 2007 by and between Northern Indiana Public Service Company, its subsidiaries, affiliates and associates ("Client", and together with other associate companies that have or may in the future execute this form of Service Agreement, the "Clients") and NiSource Corporate Services Company ("Company").

WITNESSETH:

WHEREAS, the Securities and Exchange Commission ("SEC") has approved and authorized as meeting the requirements of Section 13(b) of the Public Utility Holding Company Act of 1935 ("Act") the organization and conduct of the business of the Company, in accordance herewith, as a wholly-owned subsidiary service company of NiSource Inc. ("NiSource), including the allocation of all Company costs by using the methods approved by the Securities and Exchange Commission ("SEC Method");

WHEREAS, Client is an affiliate of the Company; and

WHEREAS, the Company and Client agree to enter into this Service Agreement whereby the Client may seek certain services from the Company and the Company agrees to provide such services upon request and upon the Company's conclusion that it is able to perform such services. Further, the Client agrees to pay for the services as provided herein at cost, with cost determined in accordance with applicable rules and regulations under the Act, which require the Company to fairly and equitably allocate costs among all Clients to which it renders services; and

WHEREAS, the rendition of such services set forth in Article 2 of Appendix A on a centralized basis enables the Clients to realize economic and other benefits through (1) efficient use of personnel and equipment, (2) coordination of analysis and planning, and (3) availability of specialized personnel and equipment which the Clients cannot economically maintain on an individual basis.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Service Agreement covenant and agree as follows:

ARTICLE 1

SERVICES

1.1 The Company shall furnish to Client, as requested by Client, upon the terms and conditions hereinafter set forth, such of the services described in Section 2 of Appendix A hereto (the "Services"), at such times, for such periods and in such manner as Client may from time to time request and that the Company concludes it is able to perform. The Company shall also provide Client with such services, in addition to those services described in Appendix A hereto, as may be requested by Client and that the Company concludes it is able to perform. In supplying such services, the Company may arrange, where it deems appropriate in consultation with Client, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services ("Additional Services").

1.2 Client shall take from the Company such of the Services, and such Additional Services, whether or not now contemplated, as are requested from time to time by Client and that the Company concludes it is able to perform.

1.3 The cost of the Services described herein or contemplated to be performed hereunder shall be allocated to Client in accordance with the SEC Method. Client shall have the right from time to time to amend or alter any activity, project, program or work order provided that (i) Client pays and remunerates the Company the full cost for the services covered by the activity, project, program or work order, including therein any expense incurred by the Company as a direct result of such amendment or alteration of the activity, project, program or work order, and (ii) Client accepts that no amendment or alteration of an activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by the Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

1.4 The Company shall hire, train and maintain an experienced staff able to perform the Services, or shall obtain experience through third-party resources, as it shall determine in consultation with Client.

ARTICLE 2

COMPENSATION

2.1 As compensation for the Services to be rendered hereunder, Client shall compensate and pay to the Company all costs, reasonably identifiable and related to particular Services performed by the Company for or on Client's behalf. The methods for allocating the Company costs to Client, as well as to other associate companies, are set forth in Appendix A.

2.2 It is the intent of this Service Agreement that charges for Services shall be billed, to the extent possible, directly to the Client or Clients benefiting from such Service. Any amounts remaining after such direct billing shall be allocated using the methods identified in Appendix A. The methods of allocation of cost shall be subject to review annually, or more frequently if appropriate. Such methods of allocation of costs may be modified or changed by the Company without the necessity of an amendment to this Service Agreement; provided that, in each instance, all services rendered hereunder shall be at actual cost thereof, fairly and equitably allocated, all in accordance with the requirements of the Act and any orders promulgated thereunder. The Company shall review with the Client any proposed change in the methods of allocation of costs hereunder and the parties must agree to any such changes before they are implemented.

2.3 The Company shall render a monthly report to Client that shall reflect all information necessary to identify the costs charged and Services rendered for that month. Client shall undertake an immediate review of the report and identify all questions or concerns regarding the charges reflected within ten (10) days of receipt of the report. If no concerns are identified within that time, Client shall remit to the Company all charges billed to it within 30 days of receipt of the monthly report.

2.4 Client agrees to provide the Company, from time to time, as requested such financial and statistical information as the Company may need to compute the charges payable by Client consistent with the method of allocation set forth on Appendix A.

2.5 It is the intent of this Service Agreement that the payment for services rendered by the Company to Client under this Service Agreement shall cover all the costs of its doing business including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, insurance, injuries and damages, employee and retiree pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and compensation for use of capital as permitted under the Act.

ARTICLE 3

TERM

3.1 This Service Agreement shall become effective as of the date first written above, subject only to the receipt of any required regulatory approvals from the State Commissions and the SEC, and shall continue in force until terminated by the Company or Client, upon not less than one year's prior written notice to the other party. This Service Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Service Agreement may conflict with (1) the Act or with any rule, regulation or order of the SEC adopted before or after the date of this Service Agreement, or (2) any state or federal statute, or any rule, decision, or order of any state or federal regulatory agency having jurisdiction over one or more Clients. Further, this Service Agreement shall be terminated with respect to the Client immediately upon the Client ceasing to be an associate company of the Company. The parties' obligations under this Service Agreement which by their nature are intended to continue beyond the termination or expiration of this Service Agreement shall survive such termination or expiration.

ARTICLE 4

SERVICE REVIEW

4.1 On an annual basis, the Company and Client shall meet to assess the quality of the Services being provided pursuant to this Service Agreement and to determine the continued need therefor and shall, subject to Section 1.1, above, amend the scope of services, delete services entirely from this Service Agreement, and/or decline services as they determine to be necessary or desirable.

4.2 NiSource maintains an Internal Audit Department that will conduct periodic audits of the Company administration and accounting processes ("Audits"). The Audits will include examinations of Service Agreements, accounting systems, source documents, methods of allocation of costs and billings to ensure all Services are properly accounted for and billed to the appropriate Client. In addition, the Company's policies, operating procedures and controls will be evaluated annually. Copies of the reports generated by the Company as part of the Audits will be provided to Client upon request.

ARTICLE 5

MISCELLANEOUS

5.1 All accounts and records of the Company shall be kept in accordance with the General Rules and Regulations promulgated by the SEC pursuant to the Act, in particular, the Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies in effect from and after the date hereof.

5.2 New direct or indirect subsidiaries of NiSource Inc., which may come into existence after the effective date of this Service Agreement, may become additional Clients of the Company and subject to a service agreement with the Company. The parties hereto shall make such changes in the scope and character of the services to be rendered and the method of allocating costs of such services as specified in Appendix A, subject to the requirements of Section 2.2, as may become necessary to achieve a fair and equitable allocation of the Company's costs among all Clients including any new subsidiaries. The parties shall make similar changes if any Client ceases to be associated with the Company.

5.3 The Company shall permit Client reasonable access to its accounts and records including the basis and computation of allocations.

5.4 The Company and Client shall comply with the terms and conditions of all applicable contracts managed by the Company for the Client, individually, or for one or more Clients, collectively, including without limitation terms and conditions preserving the confidentiality and security of proprietary information of vendors.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date and year first above written.

NISOURCE CORPORATE SERVICES COMPANY

By: Susanne M. Taylor
Name: Susanne M. Taylor
Its: Controller

NORTHERN INDIANA PUBLIC SERVICE COMPANY

By: Mark T. Maassel
Name: Mark T. Maassel
Its: President

APPENDIX A

NISOURCE CORPORATE SERVICES COMPANY

Services Available to Clients
Methods of Charging Therefor and
Miscellaneous Terms and Conditions of Service Agreement

ARTICLE 1

DEFINITIONS

1 The term "Company" shall mean NiSource Corporate Services Company and its successors.

2 The term "Service Agreement" shall mean an agreement, of which this Appendix A constitutes a part, for the rendition of services by the Company.

3 The term "Client" shall mean any corporation to which services may be rendered by the Company under a Service Agreement.

ARTICLE 2

DESCRIPTION OF SERVICES

Descriptions of the expected services to be provided by the Company are detailed below. The descriptions are deemed to include services associated with, or related or similar to, the services contained in such descriptions. The details listed under each heading are intended to be illustrative rather than inclusive and are subject to modification from time to time in accordance with the state of the art and the needs of the Clients.

1 *Accounting and Statistical Services.* The Company will advise and assist the Clients in all aspects of accounting, including financial accounting, plant accounting, regulatory accounting, tax accounting, maintenance of books and records, safeguarding of assets, accounts payable, accounts receivable, reconciliations, accounting research, reporting, operations and maintenance analysis, and related accounting functions. The Company will also provide services related to developing, analyzing and interpreting financial statements, directors' reports, regulatory reports, operating statistics and other financial reports. The Company will ensure compliance with generally accepted accounting principles and provide guidance on exposure drafts, financial accounting standards, and interpretations issued by the Financial Accounting Standards Board. The Company will advise and assist the Clients in the formulation of accounting practices and policies and will conduct special studies as may be requested by the Clients.

2 *Auditing Services.* The Company will conduct periodic audits of the general records of the Clients, will supervise the auditing of local and field office records of the Client, and will coordinate the audit programs of the Clients with those of the independent accountants in the annual examination of their accounts.

3 *Budget Services.* The Company will advise and assist the Clients in matters involving the preparation and development of budgets and budgetary controls.

4 *Business Promotion Services.* The Company will advise and assist the Clients in the preparation and use of advertising, in the development of residential, commercial and industrial business, and in the rendering of aid to local appliance distributors and dealers in the advertising and promotion of appliance sales.

5 *Corporate Services.* The Company will advise and assist the Clients in connection with corporate matters and with proceedings involving regulatory bodies.

6 *Depreciation Services.* The Company will advise and assist the Clients in matters pertaining to depreciation practices, including (1) the making of studies to determine the estimated service life of various types of plant, annual depreciation accrual rates, salvage experience, and trends in depreciation reserves indicated by such studies; (2) assistance in the organization and training of the depreciation departments of the Clients; and (3) dissemination to the Clients of information concerning current developments in depreciation practices.

7 *Economic Services.* The Company will advise and assist the Clients in matters involving economic research and planning and in the development of specific economic studies.

8 *Electronic Communications Services.* The Company will advise and assist the Clients in connection with the planning, installation and operation of radio networks, remote control and telemetering devices, microwave relay systems and all other applications of electronics to the fields of communication and control.

9 *Employee Services.* The Company will advise and assist the Clients in connection with employee relations matters, including recruitment, employee placement, training, compensation, safety, labor relations and health, welfare and employee benefits. The Company will also advise and assist the Clients in connection with temporary labor matters, including assessment, selection, contract negotiation, administration, service provider relationships, compliance, review and reporting.

10 *Engineering and Research Services.* The Company will advise and assist the Clients in connection with the engineering phases of all construction and operating matters, including estimates of costs of construction, preparation of plans and designs, engineering and supervision of the fabrication of natural gas facilities, standardization of engineering procedures, and supervision and inspection of construction. The Company will also conduct both basic and specific research in fields related to the operations of the Clients.

11 *Gas Dispatching Services.* The Company will advise and assist the Clients in the dispatching of the gas supplies available to the Clients, and in determining and effecting the most efficient routing and distribution of such supplies in the light of the respective needs therefor and the applicable laws and regulations of governmental bodies. If requested by the Clients, the Company will provide a central dispatcher or dispatchers to handle the routing and dispatching of gas.

12 *Information Technology Services*. The Company will advise and assist Clients in matters involving information technology, including management, operations, control, monitoring, testing, evaluation, data access security, disaster recovery planning, technical research, and support services. The Company will also provide and assist the Client with application development, maintenance, modifications, upgrades and ongoing production support for a portfolio of systems and software that are used by the Clients. In addition, the Company will identify and resolve problems, ensure efficient use of software and hardware, and ensure that timely upgrades are made to meet the demands of the Clients. The Company will also maintain information concerning the disposition and location of Information Technology assets.

13 *Information Services*. The Company will advise and assist the Clients in matters involving the furnishing of information to customers, employees, investors and other interested groups, and to the public generally, including the preparation of booklets, photographs, motion pictures and other means of presentation, and assistance to Clients in their advertising programs.

14 *Insurance Services*. The Company will advise and assist the Clients in general insurance matters, in obtaining policies, making inspections and settling claims.

15 *Legal Services*. The Company will provide Clients with legal services (including legal services, as necessary or advisable, in connection with or in support of any of the other services provided hereunder), including, but not limited to, general corporate matters and internal corporate maintenance, contract drafting and negotiation, litigation, liability and risk assessment, financing, securities offerings, state and federal regulatory compliance, state and federal regulatory support and rule interpretation and advice (relating to the all aspects of SEC compliance, PUHCA, FERC, FPA, PURPA), bankruptcy and collection matters, employment and labor relations investigations, union contracting, EEOC issues, and all other matters for which Clients require such legal services.

16 *Office Space*. As may from time to time be available, the Company will provide suitable space in its offices for the use of the Clients and their officers and employees.

17 *Officers*. Any Client may, with the consent of the Company, elect to any office of the Client any officer or employee of the Company whose compensation is paid, in whole or in part, by the Company. Services rendered to the Client by such person as an officer shall be billed by the Company to the Client and paid for as provided in Articles 3 and 4, and the Client shall not be required to pay any compensation directly to any such person.

18 *Operations Support and Planning Services*. The Company will advise and assist the Clients in connection with operations support and planning, including logistics and scheduling; workforce planning; corrosion and leakage programs; estimates of gas requirements and gas availability; gas transmission, measurement, storage and distribution; construction requirements; construction management; operating standards and practices; regulatory compliance; training; management of transportation and sales programs; negotiation of gas purchase and sale contracts; energy marketing and trading; security services; measurement, regulation and conditioning equipment; meter testing, calibration and repair; hydraulic gas network modeling, facility mapping and GIS technologies; and other operating matters.

19 *Purchasing, Storage and Disposition Services.* The Company will render advice and assistance to the Clients in connection with supply chain activities, including the standardization, purchase, lease, license and acquisition of equipment, materials, supplies, services, software, intellectual property and other assets, as well as shipping, storage and disposition of same. The Company will also render advice and assistance to the Client in connection with the negotiation of the purchase, sale, acquisition or disposition of assets and services and the placing of purchase orders for the account of the Client.

20 *Rate Services.* The Company will advise and assist the Clients in all rate matters, including the design and preparation of schedules and tariffs, the analysis of rate filings of producers and pipeline suppliers, and the preparation and presentation of testimony and exhibits to regulatory authorities.

21 *Tax Services.* The Company will advise and assist the Clients in tax matters, in the preparation of tax returns and in connection with proceedings relating to taxes.

22 *Transportation Services.* The Company will advise and assist the Clients in connection with the purchase, lease, operation and maintenance of motor vehicles and the operation of aircraft owned or leased by the Company or the Clients.

23 *Treasury Services.* The Company provides services such as cash management, long and short term financing for NiSource and all Clients, investment of temporarily available cash, retirement of long term debt, investment management oversight of all benefits plans, special economic studies as requested, and support for various regulatory proceedings, as requested.

24 *Land/Surveying Services.* The Company will provide land asset management, land contract management, and surveying services in connection with Clients' acquisition, leasing, maintenance, and disposal of interests in real property, including the maintenance of land records and the recording of instruments relating to such interests in real property, where necessary.

25 *Customer Billing, Collection, and Contact Services.* The Company will render calculating, bill exception processing, back office processing, posting, printing, inserting, mailing and related services to Client associated with the preparation and issuance of customer bills, notices, inserts and similar mailings. The Company will provide cash processing, revenue recovery, account reconciliations and adjustments, and related services to Client associated with the collection of revenue and management of accounts receivable. The Company will provide customer contact and related services to Client, including customer contact center management, operation and administration; management of key customer relationships; communications associated with the commencement, transfer, maintenance and disconnection of service; sales of optional products and services; the receipt and processing of emergency calls; the handling of customer complaints; and responses to customer billing, credit, collection, order take and inquiry, outage, meter reading, retail choice and other inquiries.

26 *Miscellaneous Services.* The Company will render to any Client such other services, not hereinabove described, as may properly be rendered by the Company to such Client

within the meaning and intent of the Public Utility Holding Company Act of 1935 and any other applicable statutes and the orders, rules and regulations of the Securities and Exchange Commission and any other governmental bodies having jurisdiction, as from time to time the Company may be equipped to render and such Client may desire to have performed.

ARTICLE 3

ALLOCATION METHODS

1 *Specific Direct Salary Charges to Clients.* To the extent that time spent by the officers and employees of the Company rendering services hereunder is related to services rendered to a specific Client, a direct salary charge, computed as provided in Article 4, shall be made to such Client.

2 *Apportioned Direct Salary Charges to Clients.* To the extent that the time spent by such officers and employees is related to services rendered to the Clients generally, or to any specified group of the Clients, a direct salary charge, computed as provided in Article 4, shall be made to the Clients generally, or to such specified group of the Clients, and allocated to each such Client using an allocation method approved by the Securities and Exchange Commission as set forth on Exhibit A hereto.

3 *Direct Salary Charges for Services to the Company.* To the extent that time spent by any officer or employee of the Company is related to services rendered to the Company, a direct salary charge computed as provided in Article 4 shall be allocated among the Clients in the same proportions which the direct salary charges to such Clients made pursuant to Sections 1 and 2 of this Article III, for services of officers and employees, bear to the aggregate of such direct salary charges.

4 *Apportionment of Employee Benefits.* The employee benefit expenses which are related to direct salary charges made pursuant to sub-paragraphs (1), (2) and (3) of Article 3 shall be apportioned among the Clients, as applicable, in the proportions which the respective direct salary charges made pursuant to the rendering of such services to each such Client bear to the aggregate of such direct salary charges.

5 *Other Expenses.* All expenses, other than salaries and employee benefit expenses incurred by the Company in connection with services rendered to a specific Client shall be charged directly to such Client. All such expenses incurred by the Company in connection with services rendered to the Clients generally or to any specified group of Clients shall be apportioned in the manner set forth in Section 2 of this Article 3 for the apportionment of salary charges. All such expenses incurred by the Company in connection with services rendered to the Company shall be apportioned in the manner set forth in Section 3 of this Article 3 for the apportionment of salary charges.

ARTICLE 4

COMPUTATION OF SALARY CHARGES

Direct Salary Charges The direct salary charge per hour which shall be made for the time of any officer or employee for services rendered in any calendar month shall be computed by dividing his total compensation for such month by the aggregate of (1) the number of scheduled working hours for which he was compensated, including hours paid for but not worked, and (2) hours worked in excess of his regular work schedule, whether or not compensated for.

Exhibit A

BASES OF ALLOCATION

The SEC approved Bases of Allocation shown below will be used by the Corporate Services Accounting Department for apportioning Job Order charges to affiliates. Any change in an allocation method that causes either a $50,000 or 5% change in the cost that would be charged to a company must be brought to the SEC for approval under the 60-Day Letter process.

BASIS 1

GROSS FIXED ASSETS AND TOTAL OPERATING EXPENSES

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's gross fixed assets to the total gross fixed assets of all benefited affiliates; the remaining 50% will be allocated on the basis of the relation of the affiliate's total operating expenses to the total operating expenses of all benefited affiliates. All companies may be included in this allocation.

BASIS 2

GROSS FIXED ASSETS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its total gross fixed assets to the sum of the total gross fixed assets of all benefited affiliates. All companies may be included in this allocation.

BASIS 7

GROSS DEPRECIABLE PROPERTY AND TOTAL OPERATING EXPENSE

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's total operating expenses to the total of all the benefited affiliates' total operating expense; the remaining 50% will be allocated on the basis of the relation of the affiliate's gross depreciable property to the gross depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 8

GROSS DEPRECIABLE PROPERTY

- Job order charges will be allocated to each benefited affiliate on the basis of the relationship of its total depreciable property to the sum of the total depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 9

AUTOMOBILE UNITS

- Job order charges will be allocated to each benefited affiliate on the basis of its number of automobile units to the total number of all automobile units of the benefited affiliates. All companies may be included in this allocation.

BASIS 10

NUMBER OF RETAIL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of retail customers to the total number of all retail customers of the benefited affiliates. All companies may be included in this allocation.

BASIS 11

NUMBER OF REGULAR EMPLOYEES

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of regular employees to the total number of all regular employees of the benefited affiliates. All companies may be included in this allocation.

BASIS 13

FIXED ALLOCATION

- Job order charges will be allocated to each benefitted affiliate on the basis of fixed percentages on an individual project basis. All companies may be included in this allocation.

BASIS 14

NUMBER OF TRANSPORTATION CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Transportation Customers to the total of all Transportation Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 15

NUMBER OF COMMERCIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Commercial Customers to the total of all Commercial Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 16

NUMBER OF RESIDENTIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Residential Customers to the total of all Residential Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 17

NUMBER OF HIGH PRESSURE CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its High Pressure Customers to the total of all High Pressure Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 20

DIRECT COSTS

- Job order charges will be allocated to each benefitted affiliate on the basis of the relation of its direct costs billed by Service Corporation to the total of all direct costs billed by Service Corporation. All companies may be included in this allocation.

Petitioner's Exhibit SMT-5
Northern Indiana Public Service Company
Cause No. 43526

Service Agreement

BETWEEN

NISOURCE CORPORATE SERVICES COMPANY

AND

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Dated March 31, 2005

(To Take Effect Pursuant to Article 3 Hereof)

SERVICE AGREEMENT

This SERVICE AGREEMENT (the "Service Agreement" or "Agreement") is made and entered into on this 31st day of March, 2005 by and between Northern Indiana Public Service Company, its subsidiaries, affiliates and associates ("Client", and together with other associate companies that have or may in the future execute this form of Service Agreement, the "Clients") and NiSource Corporate Services Company ("Company").

WITNESSETH:

WHEREAS, the Securities and Exchange Commission ("SEC") has approved and authorized as meeting the requirements of Section 13(b) of the Public Utility Holding Company Act of 1935 ("Act") the organization and conduct of the business of the Company, in accordance herewith, as a wholly-owned subsidiary service company of NiSource Inc. ("NiSource), including the allocation of all Company costs by using the methods approved by the Securities and Exchange Commission ("SEC Method");

WHEREAS, Client is an affiliate of the Company; and

WHEREAS, the Company and Client agree to enter into this Service Agreement whereby the Client may seek certain services from the Company and the Company agrees to provide such services upon request and upon the Company's conclusion that it is able to perform such services. Further, the Client agrees to pay for the services as provided herein at cost, with cost determined in accordance with applicable rules and regulations under the Act, which require the Company to fairly and equitably allocate costs among all Clients to which it renders services; and

WHEREAS, the rendition of such services set forth in Article 2 of Appendix A on a centralized basis enables the Clients to realize economic and other benefits through (1) efficient use of personnel and equipment, (2) coordination of analysis and planning, and (3) availability of specialized personnel and equipment which the Clients cannot economically maintain on an individual basis.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Service Agreement covenant and agree as follows:

ARTICLE 1

SERVICES

1.1 The Company shall furnish to Client, as requested by Client, upon the terms and conditions hereinafter set forth, such of the services described in Section 2 of Appendix A hereto (the "Services"), at such times, for such periods and in such manner as Client may from time to time request and that the Company concludes it is able to perform. The Company shall also provide Client with such services, in addition to those services described in Appendix A hereto, as may be requested by Client and that the Company concludes it is able to perform. In supplying such services, the Company may arrange, where it deems appropriate in consultation with Client, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services ("Additional Services").

1.2 Client shall take from the Company such of the Services, and such Additional Services, whether or not now contemplated, as are requested from time to time by Client and that the Company concludes it is able to perform.

1.3 The cost of the Services described herein or contemplated to be performed hereunder shall be allocated to Client in accordance with the SEC Method. Client shall have the right from time to time to amend or alter any activity, project, program or work order provided that (i) Client pays and remunerates the Company the full cost for the services covered by the activity, project, program or work order, including therein any expense incurred by the Company as a direct result of such amendment or alteration of the activity, project, program or work order, and (ii) Client accepts that no amendment or alteration of an activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by the Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

1.4 The Company shall hire, train and maintain an experienced staff able to perform the Services, or shall obtain experience through third-party resources, as it shall determine in consultation with Client.

ARTICLE 2

COMPENSATION

2.1 As compensation for the Services to be rendered hereunder, Client shall compensate and pay to the Company all costs, reasonably identifiable and related to particular Services performed by the Company for or on Client's behalf. The methods for allocating the Company costs to Client, as well as to other associate companies, are set forth in Appendix A.

2.2 It is the intent of this Service Agreement that charges for Services shall be billed, to the extent possible, directly to the Client or Clients benefiting from such Service. Any amounts remaining after such direct billing shall be allocated using the methods identified in Appendix A. The methods of allocation of cost shall be subject to review annually, or more frequently if appropriate. Such methods of allocation of costs may be modified or changed by the Company without the necessity of an amendment to this Service Agreement; provided that, in each instance, all services rendered hereunder shall be at actual cost thereof, fairly and equitably allocated, all in accordance with the requirements of the Act and any orders promulgated thereunder. The Company shall review with the Client any proposed change in the methods of allocation of costs hereunder and the parties must agree to any such changes before they are implemented.

2.3 The Company shall render a monthly report to Client that shall reflect all information necessary to identify the costs charged and Services rendered for that month. Client shall undertake an immediate review of the report and identify all questions or concerns regarding the charges reflected within ten (10) days of receipt of the report. If no concerns are identified within that time, Client shall remit to the Company all charges billed to it within 30 days of receipt of the monthly report.

2.4 Client agrees to provide the Company, from time to time, as requested such financial and statistical information as the Company may need to compute the charges payable by Client consistent with the method of allocation set forth on Appendix A.

2.5 It is the intent of this Service Agreement that the payment for services rendered by the Company to Client under this Service Agreement shall cover all the costs of its doing business including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, insurance, injuries and damages, employee and retiree pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and compensation for use of capital as permitted under the Act.

ARTICLE 3

TERM

3.1 This Service Agreement shall become effective as of the date first written above, subject only to the receipt of any required regulatory approvals from the State Commissions and the SEC, and shall continue in force until terminated by the Company or Client, upon not less than one year's prior written notice to the other party. This Service Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Service Agreement may conflict with (1) the Act or with any rule, regulation or order of the SEC adopted before or after the date of this Service Agreement, or (2) any state or federal statute, or any rule, decision, or order of any state or federal regulatory agency having jurisdiction over one or more Clients. Further, this Service Agreement shall be terminated with respect to the Client immediately upon the Client ceasing to be an associate company of the Company. The parties' obligations under this Service Agreement which by their nature are intended to continue beyond the termination or expiration of this Service Agreement shall survive such termination or expiration.

ARTICLE 4

SERVICE REVIEW

4.1 On an annual basis, the Company and Client shall meet to assess the quality of the Services being provided pursuant to this Service Agreement and to determine the continued need therefor and shall, subject to Section 1.1, above, amend the scope of services, delete services entirely from this Service Agreement, and/or decline services as they determine to be necessary or desirable.

4.2 NiSource maintains an Internal Audit Department that will conduct periodic audits of the Company administration and accounting processes ("Audits"). The Audits will include examinations of Service Agreements, accounting systems, source documents, methods of allocation of costs and billings to ensure all Services are properly accounted for and billed to the appropriate Client. In addition, the Company's policies, operating procedures and controls will be evaluated annually. Copies of the reports generated by the Company as part of the Audits will be provided to Client upon request.

ARTICLE 5

MISCELLANEOUS

5.1 All accounts and records of the Company shall be kept in accordance with the General Rules and Regulations promulgated by the SEC pursuant to the Act, in particular, the Uniform System of Accounts for Mutual Service Companies and Subsidiary Service Companies in effect from and after the date hereof.

5.2 New direct or indirect subsidiaries of NiSource Inc., which may come into existence after the effective date of this Service Agreement, may become additional Clients of the Company and subject to a service agreement with the Company. The parties hereto shall make such changes in the scope and character of the services to be rendered and the method of allocating costs of such services as specified in Appendix A, subject to the requirements of Section 2.2, as may become necessary to achieve a fair and equitable allocation of the Company's costs among all Clients including any new subsidiaries. The parties shall make similar changes if any Client ceases to be associated with the Company.

5.3 The Company shall permit Client reasonable access to its accounts and records including the basis and computation of allocations.

5.4 The Company and Client shall comply with the terms and conditions of all applicable contracts managed by the Company for the Client, individually, or for one or more Clients, collectively, including without limitation terms and conditions preserving the confidentiality and security of proprietary information of vendors.

Petitioner's Exhibit SMT-5
Northern Indiana Public Service Company
Cause No. 43526

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date and year first above written.

NISOURCE CORPORATE SERVICES COMPANY

By: [signature]
Name: Vincent H. DeVito
Its: Controller

NORTHEN INDIANA PUBLIC SERVICE COMPANY

By: Mark T. Maassel
Name: Mark T. Maassel
Its: President

APPENDIX A

NISOURCE CORPORATE SERVICES COMPANY

Services Available to Clients
Methods of Charging Therefor and
Miscellaneous Terms and Conditions of Service Agreement

ARTICLE 1

DEFINITIONS

1 The term "Company" shall mean NiSource Corporate Services Company and its successors.

2 The term "Service Agreement" shall mean an agreement, of which this Appendix A constitutes a part, for the rendition of services by the Company.

3 The term "Client" shall mean any corporation to which services may be rendered by the Company under a Service Agreement.

ARTICLE 2

DESCRIPTION OF SERVICES

Descriptions of the expected services to be provided by the Company are detailed below. The descriptions are deemed to include services associated with, or related or similar to, the services contained in such descriptions. The details listed under each heading are intended to be illustrative rather than inclusive and are subject to modification from time to time in accordance with the state of the art and the needs of the Clients.

1 *Accounting and Statistical Services.* The Company provides services related to developing, analyzing and interpreting financial statements, directors' reports, regulatory reports, operating statistics and other financial reports. The Company also ensures compliance with generally accepted accounting principles and provides guidance on exposure drafts, financial accounting standards, and interpretations issued by the Financial Accounting Standards Board. The Company advises and assists the Clients in the formulation of accounting practices and policies and will conduct special studies as may be requested by the Clients.

2 *Auditing Services.* The Company will conduct periodic audits of the general records of the Clients, will supervise the auditing of local and field office records of the Client, and will coordinate the audit programs of the Clients with those of the independent accountants in the annual examination of their accounts.

3 *Budget Services.* The Company will advise and assist the Clients in matters involving the preparation and development of budgets and budgetary controls.

4 *Business Promotion Services*. The Company will advise and assist the Clients in the preparation and use of advertising, in the development of residential, commercial and industrial business, and in the rendering of aid to local appliance distributors and dealers in the advertising and promotion of appliance sales.

5 *Corporate Services*. The Company will advise and assist the Clients in connection with corporate matters and with proceedings involving regulatory bodies.

6 *Depreciation Services*. The Company will advise and assist the Clients in matters pertaining to depreciation practices, including (1) the making of studies to determine the estimated service life of various types of plant, annual depreciation accrual rates, salvage experience, and trends in depreciation reserves indicated by such studies; (2) assistance in the organization and training of the depreciation departments of the Clients; and (3) dissemination to the Clients of information concerning current developments in depreciation practices.

7 *Economic Services*. The Company will advise and assist the Clients in matters involving economic research and planning and in the development of specific economic studies.

8 *Electronic Communications Services*. The Company will advise and assist the Clients in connection with the planning, installation and operation of radio networks, remote control and telemetering devices, microwave relay systems and all other applications of electronics to the fields of communication and control.

9 *Employee Services*. The Company will advise and assist the Clients in connection with employee relations matters, including recruitment, employee placement, training, compensation, safety, labor relations and health, welfare and employee benefits.

10 *Engineering and Research Services*. The Company will advise and assist the Clients in connection with the engineering phases of all construction and operating matters, including estimates of costs of construction, preparation of plans and designs, standardization of engineering procedures, and supervision and inspection of construction. The Company will also conduct both basic and specific research in fields related to the operations of the Clients.

11 *Gas Dispatching Services*. The Company will advise and assist the Clients in the dispatching of the gas supplies available to the Clients, and in determining and effecting the most efficient routing and distribution of such supplies in the light of the respective needs therefor and the applicable laws and regulations of governmental bodies. If requested by the Clients, the Company will provide a central dispatcher or dispatchers to handle the routing and dispatching of gas.

12 *Information Technology Services*. The Company provides Clients daily operational control, monitoring, data access security, disaster recovery planning, technical research, and support services to all users of the corporate network computing environment within the Company. The Company also assists the Client with application development, maintenance, and ongoing production support for a portfolio of systems that are used by the Clients. In addition, the Company will provide the Clients with an ongoing evaluation and monitoring of the network computing environment to ensure efficient use of hardware and that

timely upgrades are made to meet the demands of the Clients. The Company also maintains information concerning the disposition and location of Information Technology assets.

13 *Information Services.* The Company will advise and assist the Clients in matters involving the furnishing of information to customers, employees, investors and other interested groups, and to the public generally, including the preparation of booklets, photographs, motion pictures and other means of presentation, and assistance to Clients in their advertising programs.

14 *Insurance Services.* The Company will advise and assist the Clients in general insurance matters, in obtaining policies, making inspections and settling claims.

15 *Legal Services.* The Company will provide Clients with legal services (including legal services, as necessary or advisable, in connection with or in support of any of the other services provided hereunder), including, but not limited to, general corporate matters and internal corporate maintenance, contract drafting and negotiation, litigation, liability and risk assessment, financing, securities offerings, state and federal regulatory compliance, state and federal regulatory support and rule interpretation and advice (relating to the all aspects of SEC compliance, PUHCA, FERC, FPA, PURPA), bankruptcy and collection matters, employment and labor relations investigations, union contracting, EEOC issues, and all other matters for which Clients require such legal services.

16 *Office Space.* As may from time to time be available, the Company will provide suitable space in its offices for the use of the Clients and their officers and employees.

17 *Officers.* Any Client may, with the consent of the Company, elect to any office of the Client any officer or employee of the Company whose compensation is paid, in whole or in part, by the Company. Services rendered to the Client by such person as an officer shall be billed by the Company to the Client and paid for as provided in Articles 3 and 4, and the Client shall not be required to pay any compensation directly to any such person.

18 *Operation and Planning Services.* The Company will advise and assist the Clients in connection with estimates of gas requirements and gas available, gas transmission, measurement, storage and distribution, construction requirements, negotiation of gas purchase and sale contracts, energy marketing and trading and other operating matters.

19 *Purchasing and Storage Services.* The Company will render advice and assistance to the Clients in connection with the standardization, purchase and storage of equipment, materials and supplies, and, upon request of the Client, the negotiation of purchases and the placing of purchase orders for account of the Client.

20 *Rate Services.* The Company will advise and assist the Clients in all rate matters, including the design and preparation of schedules and tariffs, the analysis of rate filings of producers and pipeline suppliers, and the preparation and presentation of testimony and exhibits to regulatory authorities.

21 *Tax Services.* The Company will advise and assist the Clients in tax matters, in the preparation of tax returns and in connection with proceedings relating to taxes.

22 *Transportation Services.* The Company will advise and assist the Clients in connection with the purchase, lease, operation and maintenance of motor vehicles and the operation of aircraft owned or leased by the Company or the Clients.

23 *Treasury Services.* The Company provides services such as cash management, long and short term financing for NiSource and all Clients, investment of temporarily available cash, retirement of long term debt, investment management oversight of all benefits plans, special economic studies as requested, and support for various regulatory proceedings, as requested.

24 *Land/Surveying Services.* The Company will provide land asset management, land contract management, and surveying services in connection with Clients' acquisition, leasing, maintenance, and disposal of interests in real property, including the maintenance of land records and the recording of instruments relating to such interests in real property, where necessary.

25 *Miscellaneous Services.* The Company will render to any Client such other services, not hereinabove described, as may properly be rendered by the Company to such Client within the meaning and intent of the Public Utility Holding Company Act of 1935 and any other applicable statutes and the orders, rules and regulations of the Securities and Exchange Commission and any other governmental bodies having jurisdiction, as from time to time the Company may be equipped to render and such Client may desire to have performed.

ARTICLE 3

ALLOCATION METHODS

1 *Specific Direct Salary Charges to Clients.* To the extent that time spent by the officers and employees of the Company rendering services hereunder is related to services rendered to a specific Client, a direct salary charge, computed as provided in Article 4, shall be made to such Client.

2 *Apportioned Direct Salary Charges to Clients.* To the extent that the time spent by such officers and employees is related to services rendered to the Clients generally, or to any specified group of the Clients, a direct salary charge, computed as provided in Article 4, shall be made to the Clients generally, or to such specified group of the Clients, and allocated to each such Client using an allocation method approved by the Securities and Exchange Commission as set forth on Exhibit A hereto.

3 *Direct Salary Charges for Services to the Company.* To the extent that time spent by any officer or employee of the Company is related to services rendered to the Company, a direct salary charge computed as provided in Article 4 shall be allocated among the Clients in the same proportions which the direct salary charges to such Clients made pursuant to Sections 1 and 2 of this Article III, for services of officers and employees, bear to the aggregate of such direct salary charges.

4 *Apportionment of Employee Benefits.* The employee benefit expenses which are related to direct salary charges made pursuant to sub-paragraphs (1), (2) and (3) of Article 3 shall

be apportioned among the Clients, as applicable, in the proportions which the respective direct salary charges made pursuant to the rendering of such services to each such Client bear to the aggregate of such direct salary charges.

5 *Other Expenses.* All expenses, other than salaries and employee benefit expenses incurred by the Company in connection with services rendered to a specific Client shall be charged directly to such Client. All such expenses incurred by the Company in connection with services rendered to the Clients generally or to any specified group of Clients shall be apportioned in the manner set forth in Section 2 of this Article 3 for the apportionment of salary charges. All such expenses incurred by the Company in connection with services rendered to the Company shall be apportioned in the manner set forth in Section 3 of this Article 3 for the apportionment of salary charges.

ARTICLE 4

COMPUTATION OF SALARY CHARGES

Direct Salary Charges The direct salary charge per hour which shall be made for the time of any officer or employee for services rendered in any calendar month shall be computed by dividing his total compensation for such month by the aggregate of (1) the number of scheduled working hours for which he was compensated, including hours paid for but not worked, and (2) hours worked in excess of his regular work schedule, whether or not compensated for.

Exhibit A

BASES OF ALLOCATION

The SEC approved Bases of Allocation shown below will be used by the Corporate Services Accounting Department for apportioning Job Order charges to affiliates. Any change in an allocation method that causes either a $50,000 or 5% change in the cost that would be charged to a company must be brought to the SEC for approval under the 60-Day Letter process.

BASIS 1

GROSS FIXED ASSETS AND TOTAL OPERATING EXPENSES

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's gross fixed assets to the total gross fixed assets of all benefited affiliates; the remaining 50% will be allocated on the basis of the relation of the affiliate's total operating expenses to the total operating expenses of all benefited affiliates. All companies may be included in this allocation.

BASIS 2

GROSS FIXED ASSETS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its total gross fixed assets to the sum of the total gross fixed assets of all benefited affiliates. All companies may be included in this allocation.

BASIS 7

GROSS DEPRECIABLE PROPERTY AND TOTAL OPERATING EXPENSE

- Fifty percent of the total job order charges will be allocated on the basis of the relation of the affiliate's total operating expenses to the total of all the benefited affiliates' total operating expense; the remaining 50% will be allocated on the basis of the relation of the affiliate's gross depreciable property to the gross depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 8

GROSS DEPRECIABLE PROPERTY

- Job order charges will be allocated to each benefited affiliate on the basis of the relationship of its total depreciable property to the sum of the total depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 9

AUTOMOBILE UNITS

- Job order charges will be allocated to each benefited affiliate on the basis of its number of automobile units to the total number of all automobile units of the benefited affiliates. All companies may be included in this allocation.

BASIS 10

NUMBER OF RETAIL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of retail customers to the total number of all retail customers of the benefited affiliates. All companies may be included in this allocation.

BASIS 11

NUMBER OF REGULAR EMPLOYEES

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its number of regular employees to the total number of all regular employees of the benefited affiliates. All companies may be included in this allocation.

BASIS 13

FIXED ALLOCATION

- Job order charges will be allocated to each benefitted affiliate on the basis of fixed percentages on an individual project basis. All companies may be included in this allocation.

BASIS 14

NUMBER OF TRANSPORTATION CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Transportation Customers to the total of all Transportation Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 15

NUMBER OF COMMERCIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Commercial Customers to the total of all Commercial Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 16

NUMBER OF RESIDENTIAL CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its Residential Customers to the total of all Residential Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 17

NUMBER OF HIGH PRESSURE CUSTOMERS

- Job order charges will be allocated to each benefited affiliate on the basis of the relation of its High Pressure Customers to the total of all High Pressure Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania and Columbia Gas of Maryland.

BASIS 20

DIRECT COSTS

- Job order charges will be allocated to each benefitted affiliate on the basis of the relation of its direct costs billed by Service Corporation to the total of all direct costs billed by Service Corporation. All companies may be included in this allocation.

NiSource Corporate Services Company (NCS) Normalized Expenses
December 31, 2007

	Total TME 2007 Expense Col. A	IBM One-Time Items Col. B	Other One-Time Items Col. C	2007 Incentive Comp Adj. Col. D	2007 NCS Normalized Test Year Col E. = A+B+C+D	Pro-Forma Adjustments: Labor and Benefit Pro-forma Adjustment Col. F	Pro-Forma Adjustments: Incentive Compensation Pro-forma Adjustment Col. G	Pro-Forma Adjustments: IBM Fixed Contract Pro-forma Adjustment Col. H	2007 NCS Normalized Test Year With Pro-forma Adj Col. I=F+G+H	2007 NCS Net Normalized and Pro-forma Adj Col. J = A - I
Accounting and Statistical Services	3,353,445.98	(142,610.44)	(21.64)	(6,596.48)	3,204,217.42	62,675.70	(19,463.27)	-	3,247,429.85	106,016.13
Auditing Services	900,492.94	13,185.43	(6,112.20)	(2,339.68)	905,226.49	21,496.45	(6,903.34)		919,819.60	(19,326.66)
Budget Services	854,641.99	11,832.79	-	(2,291.51)	864,183.27	24,616.24	(6,761.22)		882,038.30	(27,396.31)
Business Promotion Services	1,424.68	-	(1,424.68)	-	-	-	-		-	1,424.68
Corporate Services	2,579,750.20	(597,721.57)	(27,019.46)	(3,852.54)	1,951,156.63	47,821.59	(11,367.14)		1,987,611.08	592,139.12
Customer Billing, Collection, and Contact Services	3,441,101.35	(138,017.92)	(4,207.14)	(4,879.41)	3,293,996.88	47,773.04	(14,396.97)		3,327,372.94	113,728.41
Employee Services	3,508,946.05	50,068.34	(29,738.67)	(3,626.64)	3,525,649.08	29,560.45	(10,700.60)		3,544,508.93	(35,562.88)
Engineering and Research Services	631,641.69	(97,737.55)	2.39	(1,374.40)	532,532.13	10,427.60	(4,055.24)		538,904.49	92,737.20
Gas Dispatching Services	668,686.86	18,133.58	-	(1,846.39)	684,974.05	13,525.86	(5,447.87)		693,052.05	(24,365.19)
Information Services	1,015,905.72	(3,356.02)	(65,274.77)	(2,150.87)	945,124.06	22,495.04	(6,346.26)		961,272.84	54,632.88
Information Technology Services	29,471,840.52	(2,896,272.60)	5,866.75	(2,107.18)	26,579,327.49	19,641.08	(6,217.35)	1,729,890.24	28,322,641.46	1,149,199.06
Insurance Services	982,236.97	3,845.65	(171.70)	(980.14)	984,930.78	8,284.71	(2,891.95)		990,323.54	(8,086.57)
Interest, Stock and Tax	1,197,617.06	-	-	-	1,197,617.06	-	-		1,197,617.06	-
Legal Services	5,908,805.85	(425,152.27)	(1,963.42)	(3,518.67)	5,478,171.49	38,719.73	(10,382.03)		5,506,509.19	402,296.66
Office Space	2,860,819.98	6,790.11	(813,339.03)	(2,388.30)	2,051,882.76	22,901.71	(7,046.81)		2,067,737.67	793,082.31
Operations Support and Planning Services	7,319,824.68	37,345.18	(14,138.79)	(18,718.25)	7,324,312.82	216,758.17	(55,229.22)		7,485,841.78	(166,017.10)
Purchasing, Storage and Disposition Services	2,456,288.56	169,810.82	-	(3,444.33)	2,622,655.05	26,370.23	(10,162.70)		2,638,862.58	(182,574.02)
Rate Services	3,727,275.77	8,912.80	(33,237.30)	(6,921.71)	3,696,029.56	57,482.53	(20,422.89)		3,733,089.20	(5,813.43)
Tax Services	626,360.07	8,901.60	-	(1,598.97)	633,662.70	13,983.74	(4,717.85)		642,928.60	(16,568.53)
Transportation Services	1,667,562.86	2,879.51	-	(3,193.74)	1,667,248.63	31,165.55	(9,423.30)		1,688,990.88	(21,428.02)
Treasury Services	813,525.00	8,082.00	-	(1,636.71)	819,970.29	14,107.04	(4,829.20)		829,248.13	(15,723.13)
Grand Total	73,988,194.78	(3,961,080.56)	(990,779.66)	(73,465.91)	68,962,868.65	729,806.46	(216,765.20)	1,729,890.24	71,205,800.15	2,782,394.63

Less: Amt. transferred to Reg Asset	(757,367.16)
Less: Amt. transferred to Capital or other Balance Sheet Accts	(2,882,895.38)
Net Amount Transferred from Management Fee	(3,640,262.54)
Net Management Fee TME 12/31/07	70,347,932.24

* Interest, stock compensation and tax expense are tracked separately by NCSC so that these costs can be readily identified and tracked for accounting purposes.
Pursuant to the Service Agreement with NIPSCO, these charges represent NCSC costs to maintain the service company structure.

Petitioner's Exhibit WG-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

WILLIAM GRESHAM

MANAGER OF FORECASTING

VERIFIED DIRECT TESTIMONY OF WILLIAM GRESHAM

Q1. Please state your name and business address.

A1. My name is William Gresham. My business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q2. By whom are you employed and in what capacity?

A2. I am employed by NiSource Corporate Services Company ("NCS"). My current title is Manager of Forecasting. I am submitting this testimony on behalf of Northern Indiana Public Service Company ("NIPSCO" or the "Company").

Q3. What are your responsibilities as Manager of Forecasting?

A3. As Manager of Forecasting, my principal responsibilities include developing short-range and long-range forecasts of customers, energy consumption and peak demand. I perform this activity for eleven (11) gas distribution companies and NIPSCO. I also manage other business-related analyses and forecasts.

Q4. What is your educational background?

A4. I attended Oklahoma State University where I earned a Bachelor of Science Degree in Business Administration and a Master of Science Degree in Economics.

Q5. What are your professional credentials?

A5. I served on the Ohio Governor's Economic Advisory Council and the Ohio Gas Association Forecasting and Planning Committee. I also participated as a member of the American Gas Association Forecast Methods Committee and organized and acted as the first president of the Columbus (Ohio) Association for Business Economics. I currently am a member of the Southern Gas Association's Forecasters Interest Group Steering Committee.

Q6. Please briefly describe your professional experience.

A6. From 1978 to 1982, I worked as a forecast analyst responsible for residential and commercial customer and energy forecasts for Houston Lighting and Power Company, an investor-owned electric utility. From 1982 to 1985, I was a senior business analyst for the oilfield equipment division of ARMCO, Inc. where I developed product-line forecasts and assisted in strategic planning. As Director of Research at Rice Center, a consulting company affiliated with Rice University in Houston, Texas, I supervised an economics section and managed economic and demographic consulting projects from 1985 to 1987.

In 1987, I joined Columbia Energy Group as Demand Research Coordinator responsible for developing forecasts of customers and energy consumption for six (6) gas distribution companies. I was promoted to Manager of Forecasting in 1990, a post I held until the merger with NiSource Inc. ("NiSource") in 2000. I am now Manager of Forecasting for NiSource.

Q7. Have you previously testified before this or any other regulatory commission?

A7. I have provided testimony concerning forecasting and weather normalization in regulatory proceedings in Indiana, Kentucky, Maryland, Massachusetts, Ohio, Pennsylvania and Virginia.

Q8. What is the purpose of your testimony in this proceeding?

A8. My testimony will explain how test year kilowatt hour ("KWH") consumption was adjusted to reflect the KWH consumption that would have occurred had weather been normal. I will also explain why this is the appropriate level to use for ratemaking. I will also explain the base load/temperature-sensitive load normalization procedure.

I. WEATHER NORMALIZATION

Q9. Why is an adjustment to electric utility revenues to normalize weather appropriate?

A9. Electric rates include charges that are tied to KWH consumption. These charges are developed by dividing required revenue by KWH consumption from the test year. Because these charges are dependent on KWH consumption, variations in weather will affect the costs allocated to each KWH. For example, calculating these charges based on a test year with abnormally high consumption will result in a lower allocation of costs to each KWH consumed. When consumption returns to more normal levels after the test year, the electric utility will be unable to collect the revenue upon which rates were based.

Q10. Has NIPSCO historically calculated weather normalized revenues?

A10. Yes, it has. The Indiana Utility Regulatory Commission ("Commission") approved NIPSCO's calculation of weather normalized revenues for its electric utility in its Orders in Cause No. 36689 dated August 11, 1982 and Cause No. 36394 dated September 16, 1981.

Q11. Was the weather during the test year used by NIPSCO abnormal?

A11. Yes. Cooling Degree Days ("CDD") for the months May through October (referred to as a "CDD Season") were 17% higher than the average for the 30-year period ended 2005.

Q12. What is CDD?

A12. CDD is a unit used to relate a day's temperature to the energy demands of air conditioning. CDD are calculated by subtracting 65 from a day's average temperature. For example, if the day's high temperature is 90°F and the day's low temperature is 70°F, the day's average temperature is 80°F. CDD are calculated by subtracting 65 from 80 making that day's CDD 15. CDD can be used to compare the current CDD Season to a past CDD Season.

Q13. How can CDD be used to compare the current CDD Season to a past CDD Season?

A13. CDD are accumulated daily so that a month's CDD is the sum of the daily CDD. A high level of CDD indicates many days with high temperatures and is associated with a high level of KWH consumption. The level of CDD can be compared from month-to-month or summer-to-summer to indicate the relative amount of hot weather. The 955 CDD during the CDD Season of the test year is much higher than the average of 814 CDD during the CDD Season for the 30 year period 1976 to 2005. In fact, the CDD during the CDD Season of the test year is the 9th highest CDD Season for the 47 year period 1961 to 2007, which has an average of 787 CDD during the CDD Season.

Q14. Why have you relied on a 30-year CDD average ended 2005?

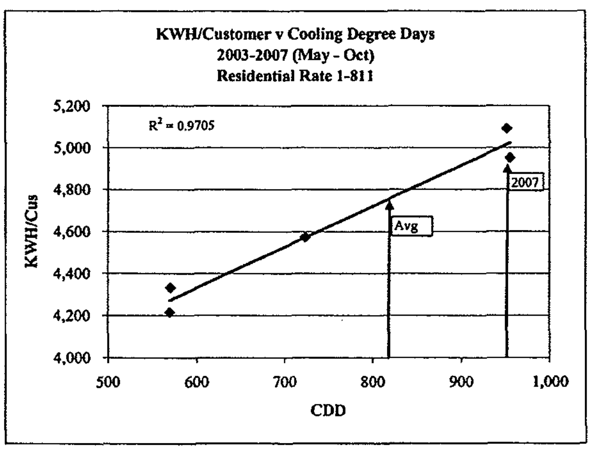
A14. This averaging period represents an update to the normal CDD calculated by the National Oceanic and Atmospheric Administration's National Weather Service, which uses data for the 30 year period ended 2000. Additionally, the timeframe is the same period that NIPSCO uses to weather normalize its financial and operations plans.

Q15. Please discuss electric consumption due to higher than average CDD during the test year?

A15. In simple terms, the data indicates that during the CDD Season, either the days were hotter than average or there were more hot days than average resulting in customers operating their air conditioners more than normal and thereby consuming more electric energy than normal. I can conclude, based on this data, that the amount of electric energy consumed during the test year is abnormally high and that the test year does not reflect a representative level for ratemaking purposes.

Q16. Does the data show that KWH consumption varies with CDD?

A16. Yes, it does. The relationship between CDD and KWH consumption per customer for the CDD Season during the period 2003 to 2007 for the residential 1-811 rate is depicted in the following graph:



The graph shows a strong correlation between CDD and electric energy consumed. The graph also shows that the 955 CDD and the KWH consumed during the CDD Season of the test year are abnormally high when compared to the average of 814 CDD. In fact, as noted above, it is the 9th highest CDD Season for the 47 year period 1961 to 2007. In other words, the test year had more CDD than 80 percent of the past 47 years.

Q17. What do you conclude from this data?

A17. A strong relationship between KWH consumption and CDD combined with CDD exceeding the level observed in 80 percent of the past 47 years, leads to the conclusion that KWH consumption should be normalized for weather so that it is stated at a level representative for ratemaking purposes.

II. WEATHER NORMALIZATION PROCEDURE

Q18. What procedure did you use to normalize revenue for weather?

A18. I used a base load/temperature-sensitive load normalization procedure. This procedure identifies a level of KWH/Customer that is not dependent on weather (base load) and subtracts that from total KWH/Customer to derive temperature-sensitive KWH/Customer. The temperature-sensitive KWH/Customer is then multiplied by the ratio of normal CDD to actual CDD to obtain normal temperature-sensitive KWH/Customer. The normal temperature-sensitive KWH/Customer is then added to the base load KWH/Customer to arrive at the normal total KWH/Customer which is then multiplied by the number of customers to yield the normal KWH for the month. I used the following data sources to conduct my analysis:

- NIPSCO billing records for monthly customer count and KWH sales
- National Weather Service Weather Stations for temperatures used to calculate CDD. Weighted average CDD is calculated using the percent of residential customers assigned to the each station as a weight for that station.
- Normal weather is the (30-year) average of 1976-2005

The weather normalization procedure I used follows:

Procedure:

- Assume no temperature-sensitive load in April
- Base Load/Customer/Day = April

For each month:

- Base Load/Customer = the lesser of
  Base Load/Customer/Day * Days in the month or Total Load/Customer
- Temperature Sensitive Load/Customer =
  Total Load/Customer – Base Load/Customer
- Normal Temperature Sensitive Load/Customer =
  Temperature Sensitive Load/Customer * (Normal CDD/Actual CDD)
- Normal Load/Customer =
  Base Load/Customer + Normal Temperature Sensitive Load/Customer
- Normal Volume =
  Customers * Normal Load/Customer

Q19. Has this normalization procedure been accepted by the Commission?

A19. Yes. This normalization procedure is the same general procedure used and approved in Cause Nos. 36689 and 36394.

Q20. Did you modify the normalization procedure used in Cause Nos. 36689 and 36394 for your analysis?

A20. Yes. Changes have been made to address the Commission's suggestion that NIPSCO use weather data that accounts for geography, demography and any special climatic conditions such as the lake effect. There were also some minor modifications made to account for CDD during the CDD Season. I discuss these modifications below.

Q21. How have you accounted for geography, demography and any special climatic conditions such as the lake effect?

A21. I selected the Valparaiso weather station in place of the Chicago weather station to represent the western portion of the service territory more accurately. Valparaiso is located in the service territory on the side of Lake Michigan that experiences the lake effect that applies to NIPSCO's customers. I also adjusted the weather station weights to reflect the distribution of customers and load in the service territory. The previous equal weighting has been replaced by Valparaiso (63%), South Bend (19%) and Fort Wayne (18%).

Q22. Why do you establish a base load as part of the normalization procedure?

A22. There is a certain level of KWH consumption that will occur every month regardless of weather. That consumption will be for end uses such as lighting, electronic entertainment devices, water heating and refrigeration. Because adjusting non-temperature-sensitive consumption for abnormal weather would be inappropriate, non-temperature-sensitive consumption for abnormal weather is eliminated from the procedure by subtracting it from total consumption, leaving only temperature-sensitive consumption to be adjusted.

Q23. Why did you choose April as the base load month?

A23. I selected April because that month has the least amount of weather that can affect the level of KWH/Customer. April typically has few or no CDD and relatively few Heating

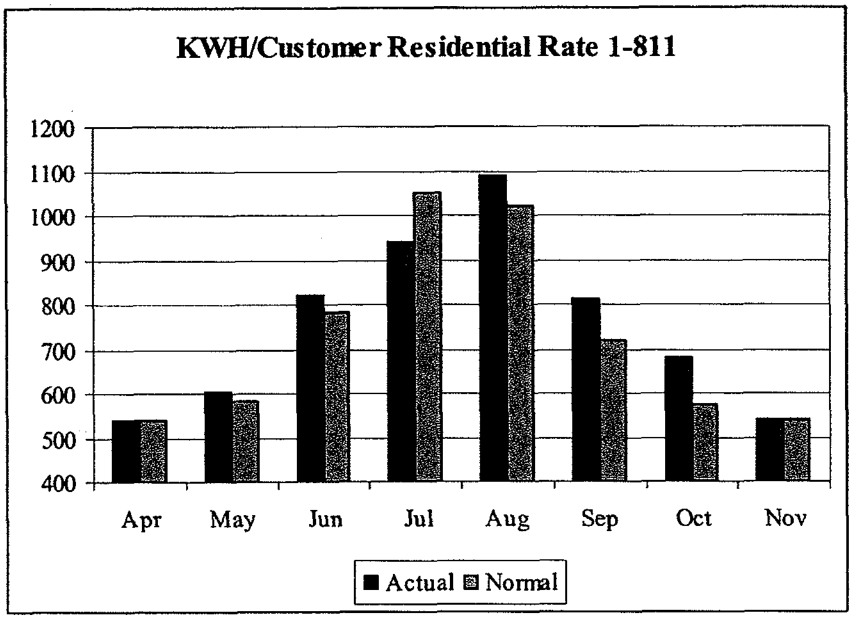
Degree Days ("HDD"). Additionally, April typically has the lowest level of monthly KWH/Customer usage during the year.

Q24. Is April always the base load month?

A24. April was used as the base load month for seven (7) of the eight (8) rates that were weather normalized. November was used for the residential heat pump 2-812 rate. Heat pumps can be used intensively in transition months such as October, that could require either heating and/or cooling. When a hot October such as the one in the test year delays the start of the heating season, it is not surprising that November is a low KWH/customer month for the customers on the heat pump rate. While April may have less cold weather than November, the response to cold weather is less at the beginning of the Winter Season than at the end.

Q25. Are May and October always normalized for weather?

A25. No. In years when CDD in May or October are very few, the consumption response is often negligible. In 2007 (the test year in this proceeding), this was not the case. In 2007, there were 100 CDD in May and 53 CDD in October. The following graph for the residential 1-811 rate shows that October in particular was notably above the base load month of April. This was a result of a hot period that occurred in the first eight days in the month.



Q26. Did you adjust for winter HDD?

A26. No. HDD is an index designed to reflect demand for energy for space heating. NIPSCO's electric heating saturation for residential customers is low at about 6%. Because of the low saturation, no adjustment was made for HDD.

III. <u>RESULTS OF WEATHER NORMALIZATION</u>

Q27. What are the results of your weather normalization?

A27. The weather normalization adjustment reduces volume in five (5) and adds volume in one (1) of the six (6) months in the CDD Season. The net effect is a reduction of 163,303 MWH or 2.2% of the annual volume for the adjusted rates.

Q28. What adjustments is NIPSCO making to reflect the weather normalization?

A28. NIPSCO is proposing to reduce test year operating revenue levels by $14,604,146 to reflect a normalized level of revenue at NIPSCO's tariff rates. NIPSCO also proposes a corresponding reduction to test year operating expense of $3,683,450 to reflect the fuel costs included in their base rates that would result in a normal year. No adjustment has been made to fuel costs or purchased power costs not included in base rates because the revenues and expenses associated with normalizing for weather would net out in the fuel adjustment clause.

Q29. Does this conclude your prepared direct testimony?

A29. Yes, it does.

VERIFICATION

I, William Gresham, Manager of Forecasting for NiSource Corporate Services Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

William Gresham

William Gresham

Date: August 29, 2008

INDS01 PJS 1040351

Petitioner's Exhibit JMO-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

JOHN M. O'BRIEN

ASSISTANT CONTROLLER OF TAXES

SPONSORING PETITIONER'S EXHIBIT JMO-2

VERIFIED DIRECT TESTIMONY OF JOHN M. O'BRIEN

Q1. Please state your name and business address.

A1. My name is John M. O'Brien. My business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q2. By whom are you employed and in what capacity?

A2. I am employed by NiSource Corporate Services Company ("NCS"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Assistant Controller of Taxes at NCS. I am a tax officer of all the subsidiaries of NiSource as well, which includes Northern Indiana Public Service Company ("NIPSCO" or the "Company").

Q3. Please describe your educational background.

A3. I received Bachelor of Science Degrees in Economics in 1977 and in Accounting in 1980 from the University of Delaware. In December 1985, I received my Masters in Tax from Drexel University.

Q4. Please briefly describe your professional experience.

A4. I have been employed by NCS and Columbia Energy Group subsidiaries since 1980. I started as an accountant with Columbia and moved into the Columbia Gas System Service Corporation tax department in 1984 as a senior accountant. In late 1988, I accepted a transfer to an affiliate, Columbia Gas Transmission Corporation ("CGT"). I was employed by CGT until January 2001, holding various positions in tax management. At the time of the merger with NiSource, I was Vice President of Tax. In January 2001, I accepted my current position with NCS.

Q5. What are your responsibilities in your current position?

A5. In my current position with NCS, I am responsible for, and have oversight of, tax accounting, tax planning and tax compliance of all subsidiaries of NiSource. These responsibilities include all tax activities for NIPSCO. I oversee the preparation of income and non-income tax returns, excluding payroll, and approve the associated accounting of those taxes on the books.

Q6. Have you reviewed the exhibits of NIPSCO Witness Linda E. Miller to the extent they include expense adjustments for federal and state taxes?

A6. Yes, I have.

Q7. Did you participate in the quantification of those adjustments?

A7. Yes, I did.

Q8. What is the purpose of your direct testimony in this proceeding?

A8. The purpose of my direct testimony is to present and support NIPSCO's federal and state income tax expense adjustments and the adjustments for taxes other than income included in the cost of service shown in the accounting exhibits of Ms. Miller.

Q9. Have you prepared an exhibit relating to those subjects?

A9. Yes. I have prepared <u>Petitioner's Exhibit JMO-2</u> which provides a detailed explanation of the calculation of the federal and state tax expense amounts included in Ms. Miller's accounting exhibits.

I. <u>FEDERAL INCOME TAX EXPENSE</u>

Q10. Please describe the basic components of federal income tax expense reflected in Ms. Miller's accounting exhibits

A10. At its most basic level, the quantification of federal income tax expense begins with the application of the 35% federal income tax rate applied to pro forma net operating income less interest expense. This amount was adjusted to account for the following five issues:

(i) Adjustment to reflect the various impacts for the differences between the use of accelerated depreciation for income tax return purposes and straight line depreciation in determining tax expense for regulatory and book purposes;

(ii) Adjustment to reflect certain limitations on the amount of the federal income tax deduction that may be taken on certain categories of expense;

(iii) Reduction in tax expense for Amortization of Investment Tax Credits;

(iv) Reduction in tax expense for Section 199 Manufacturing Credit; and

(v) Reduction in tax expense for allocation of parent company (NiSource) interest expense.

Q11. How is the amount of the interest expense deduction calculated?

A11. The interest expense deduction was determined using the interest synchronization method. Under this method, the interest expense deduction is calculated to be $50,341,823 by multiplying NIPSCO's original cost electric rate base (shown in Ms. Miller's exhibits to be $2,341,480,136) by the weighted cost of debt computed from a capital structure that excludes investment tax credits (2.15%). This method results in an appropriate level of interest to reflect for purposes of setting electric rates.

Q12. Would you please explain the issues arising from the use of accelerated depreciation for income tax purposes?

A12. On the federal income tax return, depreciation expense is deducted using accelerated rates provided for in the Internal Revenue Code. Accelerated depreciation for tax purposes is intended to provide companies with an incentive to make investments that improve the economy and provide other public benefits. For regulatory and book purposes, the depreciation expense deduction is calculated on a straight line basis over the life of the property using depreciation rates approved by the Commission. The regulatory and book treatment included in the income tax component of cost of service is referred to as the normalization method of accounting and is required by the Internal Revenue Code. The difference between accelerated and normalized depreciation is a timing (or temporary) difference – the same amount of depreciation expense ultimately will be deducted for tax and book purposes, but the depreciation expense deduction will be reflected in different time periods. These timing differences are accounted for on NIPSCO's balance sheet by recording temporary deferred tax reserves. Adjustments to the federal income tax expense amount are required, however, due to the use of a different methodology prior to November 1975 and due to tax rate changes in certain prior years.

Q13. Please address the adjustment that is necessary due to the use of a different method prior to November 1975.

A13. Prior to November 1975, for ratemaking purposes NIPSCO's income tax expense was calculated utilizing the shorter tax lives of the assets. This method had the effect of flowing through to ratepayers the tax benefits associated with a higher depreciation expense deduction in the early years of the asset's service life with the consequence being correspondingly greater tax expense for ratemaking purposes in the later years of the asset's service life. This flow through of the tax benefit was not complete, however, because prior to November 1975, deferred taxes were recorded on method differences (*e.g.*, double declining balance versus straight line).

Today, income tax expense for regulatory and book purposes is calculated using the normalization method of accounting, which calculates income tax expense using the depreciation expense amount recorded for book purposes. For book purposes, depreciation expense is spread over the service life of the asset in equal amounts each year and the difference between tax expense computed using book depreciation and tax expense computed using tax depreciation is included in the deferred tax reserve. However, due to the fact that a partial flow through method was used before November 1975, the Company's deferred tax reserve is insufficient. For the most part, pre-

November 1975 property is fully depreciated for tax purposes, and, therefore, the per book depreciation expense amount exceeds the amount allowed on the tax return. This deficiency in the deferred tax reserve requires an adjustment to the federal income tax expense amount used for ratemaking purposes.

Q14. Are there other differences between what is depreciated for income tax purposes and for regulatory and book purposes?

A14. Yes. For regulatory and book purposes, the Company records Allowance for Funds Used During Construction ("AFUDC") to reflect a return on the equity portion of capital while an asset is under construction and before it is placed in service ("AFUDC Equity"). These amounts are capitalized to the cost of the asset and depreciation expense is recorded for book purposes on the total cost. For income tax purposes, however, no deduction is allowed for the depreciation expense associated with the amounts recorded as AFUDC Equity. This is not a timing difference as discussed above because the depreciation of the capitalized AFUDC Equity only occurs on the books. Thus, income tax expense for ratemaking purposes must be adjusted to reflect that this expense will never be deductible for income tax purposes.

Q15. Have you computed the total adjustment necessary due to the partial flow method used before November 1975 and the fact that AFUDC Equity is not deductible for income tax purposes?

A15. Yes. For both the pre-November 1975 issue (turnaround of the prior flow through tax benefits) and the AFUDC Equity issue (recovery of taxes on AFUDC Equity), the

Company proposes to recover the deficiency over the remaining service life of the assets. The total adjustment for these two issues is an increase in income tax expense of $6,244,423. The majority of this increase in income tax expense relates to AFUDC Equity capitalized on construction activities in the 1970s and 1980s, including construction at the R.M. Schahfer Generation Station.

Q16. Are there other adjustments that need to be made to account for differences in the treatment of depreciation expense?

A16. Yes. As I explained previously, since November 1975, the effect of accelerated depreciation has been normalized by providing deferred tax reserves, rather than flowed through in NIPSCO's rates. In 1981, Congress made full normalization for ratemaking purposes a requirement for utilities to use accelerated depreciation for income tax purposes. As I indicated previously, this results in temporary or timing differences that are reflected in deferred tax reserves.

The calculation is complicated, however, when there is a change in the statutory federal corporate income tax rate between the time when the deduction is taken for income tax purposes and the time when depreciation expense is recorded for ratemaking purposes. In 1986, Congress reduced the corporate federal income tax rate to 34%. This change was effective in mid-1987. As a result of this tax rate change, NIPSCO recorded excess deferred taxes on its depreciable property prior to 1988.

Q17. How is the Company handling the excess deferred taxes in this rate filing?

A17. An adjustment for the excess amount is included in the income tax expense reflected in NIPSCO's accounting exhibits. Under Section 203(e) of the Tax Reform Act of 1986, the Company is to refund this excess over the service life of the pre-1988 assets. This is commonly referred to as the Average Rate Assumption Method (ARAM). The amortization begins on a class of assets when book depreciation exceeds tax depreciation. The total adjustment for this issue is a reduction in income tax expense of $2,931,718.

Q18. What is the total adjustment to income tax expense associated with the three impacts you have described?

A18. The total adjustment caused by partial flow through before November 1975, by the non-deductibility of depreciation on AFUDC Equity, and by the change in the federal income tax rate is an increase in federal income tax expense of $3,312,705.

Q19. Have any other adjustments been made for expenses that are not deductible for income tax purposes?

A19. Yes. The Company is not permitted to deduct on its tax return 50% of its business meals and entertainment expenditures. The Company has adjusted its federal income tax expense upward by $135,084 to reflect the non-deductibility of these expenses.

Q20. Please explain the adjustment relating to the amortization of Investment Tax Credits that is included as a reduction to federal income tax expense.

A20. The Company is amortizing investment tax credits that it reflected on federal tax returns prior to 1989 over the service life of the property that generated the credits. The investment tax credit was repealed as part of the Tax Reform Act of 1986, with transition rules that permitted certain projects to qualify post-1986. A balance of $25,019,476 of electric investment tax credits remains deferred as of December 31, 2007. For the year 2008, NIPSCO will amortize $4,556,906 of previously deferred credits. This results in an adjustment to decrease income tax expense.

Q21. What is the Section 199 deduction and how does it impact rates?

A21. In 2004, Congress passed the American Jobs Creation Act, which enacted Section 199 of the Internal Revenue Code. This section allows a taxpayer to deduct a percentage of its manufacturing income. For NIPSCO, this deduction only pertains to taxable income from its generation business. The Company does not receive a Section 199 deduction for income derived from its electric transmission and distribution business. In 2007, as well as 2008, the deduction is 6% of generation taxable income. Based on historic years and previous allocations, the Company estimates its test year generation taxable income to be $155,078,183 based on its allocation of total revenue to generation income compared to electric transmission and distribution income. At 6%, this would entitle the Company to a deduction in the amount of $9,304,691. At 35%, the tax benefit is $3,256,642. NIPSCO's income tax expense has been adjusted downward by this amount.

Q22. What adjustment have you made for parent company interest expense?

A22. NIPSCO's parent company, NiSource, has additional interest expense obligations relating to the ongoing utility operations of NiSource's public utility subsidiaries. The Company has allocated a portion of the tax benefit on this interest expense to NIPSCO. This allocation was based on NiSource's equity investment in NIPSCO compared to its equity investment in all subsidiaries. The amount of the adjustment is a reduction in income tax expense of $1,122,881.

II. <u>STATE INCOME TAX EXPENSE</u>

Q23. What level of income tax expense is included for state income taxes?

A23. The tax calculations include Indiana Adjusted Gross Income taxes at 8.5% as adjusted for the following three reconciling items:

(i) The non-deductibility of Utility Receipts Tax;

(ii) The deferred tax deficiency resulting from the increase in the state tax rate from 4.5% to 8.5%; and

(iii) The non-deductibility of certain expenses.

Q24. Please explain the adjustment for non-deductibility of Utility Receipts Tax.

A24. Under Indiana Code § 6-3-1-3.5(b)(3), the Company is not permitted to deduct its Utility Receipts Tax on its Indiana Adjusted Gross Income tax return. At an 8.5% tax rate, the test year pro forma Utility Receipts Tax of $11,905,630 results in an additional tax expense of $1,011,979 under NIPSCO's present rates.

Q25. Please explain the adjustment for the state deferred tax deficiency.

A25. The deferred tax deficiency due to the state tax rate change is much like what resulted from the reduction in the federal tax rate in 1986, but the result is the opposite because the state tax rate increased. In 2002, the Indiana legislature increased the Adjusted Gross

Income tax rate from 4.5% to 8.5%. Based on accelerated tax deductions in excess of book expense, the Company had approximately $1.5 billion in accelerated deductions for its electric business. The deferred tax requirement thus changed from 4.5% of $1.5 billion ($67.5 million) to 8.5% of $1.5 billion ($127.5 million), resulting in a $60 million deferred tax deficiency.

Starting in 2003, when the new tax rate went into effect, the $60 million deferred tax deficiency has been amortized as the underlying accelerated tax deductions have turned around. At the end of 2007, the Company had a balance of $32,224,744 in state deferred income tax deficiency. During 2008, the Company will incur additional current state income taxes of $4,429,032 as a result of additional turn around of accelerated tax deductions and the deferred tax deficiency will decrease by a similar amount. Similar to the federal excess and deficiency, recovery of the state income taxes occurs over the regulatory life of the assets. The Company has adjusted test year state income tax expense by $4,429,032 for the state deferred tax deficiency.

Q26. Please explain the adjustment for non-deductibility of certain expenses?

A26. The State of Indiana follows federal law on the non-deductible portion of business meals and entertainment expenses. The Company has adjusted test year state income tax expense upward by $21,324 to reflect the tax impact.

III. <u>REAL AND PERSONAL PROPERTY TAXES</u>

Q27. Please explain the Company's proposal to reflect $30 million in real and personal property taxes.

A27. NIPSCO is subject to real and personal property taxes in 31 counties in Indiana. It is also subject to property taxes on rail cars in 10 states. The Company recorded $32.6 million in electric property tax expense for the 2007 year after adjustment for the allocation between electric and gas operations. At this point in time, the Company has not received its 2007 statements for all Indiana counties.

Q28. Please explain the recent tax changes in property taxes in Indiana and the impact on NIPSCO.

A28. The recent tax changes from House Enrolled Act 1001 included substantial shifting of funding and responsibilities from local to state government. The most significant provisions deal with property tax "circuit breakers" that limit a taxpayer's property tax liability to a percentage of that property's assessed value. The circuit breakers applicable to NIPSCO are for nonresidential real property and personal property classifications. These circuit breakers are 3.5% for taxes assessed in 2008 and payable in 2009 and decrease to 3.0% for taxes assessed in 2009 and payable in 2010. However, the counties of Lake and St. Joseph may exceed the circuit breaker to the extent of debt service requirements acquired before July 1, 2008. NIPSCO has substantial property in these combined counties for which the amount of the circuit breakers is currently unknown. In addition, NIPSCO has little if any property in any tax districts other than Lake and St. Joseph Counties that currently would receive any benefit from the circuit breakers.

House Enrolled Act 1001 also included a provision stating that the owner of an industrial plant in Jasper County with an assessed value that exceeds 20% of the total taxable assessed value in the county for 2006 is not entitled to receive local property tax replacement credits otherwise payable from Local Option Income Taxes ("LOIT"). The only taxpayer impacted by this provision is NIPSCO caused by its ownership of the R. M. Schahfer Generating Station. The Legislative Services Agency has estimated that NIPSCO will lose $1.2 million of credits it would have been entitled to absent this provision.

The shifting of funding and responsibilities from local to state government will occur primarily through an increase in the state sales tax rate from 6% to 7% effective April 1, 2008.

At this point, the Company cannot estimate the impact of the recent tax changes in property taxes in Indiana on its 2008 and future property tax expense. Given this uncertainty, NIPSCO is not proposing an adjustment related to House Enrolled Act 1001.

Q29. Have you calculated the Company's property taxes that will be incurred in connection with the Company's newly acquired Sugar Creek generating facility?

A29. Yes, the Company has included $1,132,243 for property taxes based on the June 2010 through May 2011 projected liability. The amounts have been adjusted by the abatement percentage on the taxable value of the plant for the 2010-2011 period.

IV. UTILITY RECEIPTS TAX

Q30. Please explain how the Utility Receipts Tax is computed.

A30. NIPSCO is subject to a 1.4% Utility Receipts Tax on all receipts except sales for resale. For the year 2007, the Company recorded Utility Receipts Taxes of $18,372,838. On a pro forma basis under the Company's present rates, the operating revenues quantified by Ms. Miller would result in Utility Receipts Tax of $11,905,630, requiring a downward adjustment of $6,467,208. The major reason for this significant adjustment is the Company's proposal to remove the cost of fuel and purchased power from base rates as explained by NIPSCO Witness Frank A. Shambo. If the cost of fuel and purchased power is to be recovered entirely through trackers, then the Utility Receipts Tax associated with recovering the cost of fuel and purchased power during the test year should also be removed from base rates. The Utility Receipts Tax associated with the cost of fuel and purchased power will be recovered through the Company's separate fuel adjustment clause and tracker filings.

V. SUMMARY

Q31. Please describe Petitioner's Exhibit JMO-2.

A31. Schedule 1 of Petitioner's Exhibit JMO-2 shows the derivation of the Company's federal and state income tax expense reflecting each of the adjustments previously described in my testimony. Schedule 2 of Petitioner's Exhibit JMO-2 shows the calculation of the effect on the Company's tax expense of the adjustments for excess and deferred taxes, the limitation on the deductibility of meals and entertainment expenses, the investment tax credit amortization, the Section 199 deduction, the parent company interest allocation and the Indiana Utility Receipts Tax.

Q32. Are the tax expense adjustments reflected in Ms. Miller's exhibits correct and consistent with the matters described above?

A32. Yes, they are.

Q33. Does this conclude your prepared direct testimony?

A33. Yes, it does.

VERIFICATION

I, John M. O'Brien, Assistant Controller of Taxes, for NiSource Corporate Services Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

John M. O'Brien

John M. O'Brien

Date: August 29, 2008

INDS01 CEARLS 1057132

Petitioner's Exhibit JMO-2
Cause No. 43526
Schedule 1

Northern Indiana Public Service Company
Income Tax Expense Included In Pro Forma Income

Description	Amount
Net Operating Income	181,283,030
Plus: Income Taxes Included in Net Operating Income	88,580,793
Net Operating Income Before Taxes	269,863,823
Interest Synchronization Deduction	(50,341,823)
Federal Taxable Income Before State Tax Deduction	219,522,000
Less: State Income Taxes at 8.5%	18,659,370
Federal Taxable Income	200,862,630
Federal Income Taxes at 35%	70,301,921
Other Components of Income Tax Expense	
Federal Income Taxes	
Net Deficient Deferred Taxes	3,312,705
Permanent Differences: Meals	135,084
Investment Tax Credit Amortization	(4,556,906)
Section 199 Deduction	(3,256,642)
Parent Company Tax Benefit of Interest Expense	(1,122,881)
Subtotal	(5,488,640)
State Income Taxes	
Net Deficient Deferred Taxes	4,429,032
Permanent Differences: Meals	21,324
Permanent Differences: Utility Receipts Tax	657,786
Subtotal	5,108,142
Summary:	
Federal Income Taxes	64,813,281
State Income Taxes	23,767,512
Total Income Taxes Included In Pro Forma Calculation	88,580,793

Northern Indiana Public Service Company
Adjustments to Income Tax Allowance

Description	Balance at December 31, 2007	Projected at December 31, 2008	Amortization or Tax Allowance
Excess & Deficient Deferred Taxes			
Net Excess for Method and Life Differences	(17,658,545)	(14,726,827)	(2,931,718)
Deficiency for Flow Through and AFUDC Equity	35,357,171	29,112,748	6,244,423
Deficiency for State Income Taxes	32,224,744	27,795,712	4,429,032
Total	49,923,370	42,181,633	7,741,737

	Projected 2008 Non-Deductible Exp.	Tax Rate	Tax Allowance
Permanent Differences			
Meals & Entertainment (Federal)	385,953	35%	135,084
Meals & Entertainment (State net of Federal)	385,953	5.525%	21,324

	Balance at December 31, 2007	Projected at December 31, 2008	Amortization or Tax Allowance
Investment Tax Credit Amortization			
Vintage Years 1978-1988 (account 255)	(25,019,476)	(20,462,570)	(4,556,906)

Section 199 Deduction	Projected Taxable Generation Income	Deduction Percent	Tax Allowance
Taxable Income	155,078,183	-6%	(9,304,691)
Tax Rate			35%
Tax Allowance			(3,256,642)

	Projected Allocation		Tax Allowance
Parent Company Tax Benefit of Interest Expense			
Interest Expense on Parent	14,132,154		
Percent Allocated to NIPSCO Based on Investment	26.3055%		
Subtotal	3,717,534		
Electric Percentage	86.30%		
Tax Loss Allocated to Electric	3,208,232		
Tax Rate	35%		
Tax	(1,122,881)		(1,122,881)

State Income Tax Allowance for URT	Non-Deductible Expenses	Tax Rate	Tax Allowance
Projected URT Expense	11,905,630	8.5%	1,011,979
Federal Benefit			(354,193)
Tax Allowance			657,786

Total Federal and State Tax Adjustments to Statutory Rate (380,498)

Petitioner's Exhibit PWP-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

PHILIP W. PACK

MANAGER, MAJOR PROJECTS & RESOURCE DEVELOPMENT

SPONSORING PETITIONER'S EXHIBITS PWP-2 THROUGH PWP-5

VERIFIED DIRECT TESTIMONY OF PHILIP W. PACK

Q1. Please state your name and business address.

A1. My name is Philip W. Pack. My business address is 2755 Raystone Drive, Valparaiso, Indiana, 46383.

Q2. By whom are you employed and in what capacity?

A2. I am employed by Northern Indiana Public Service Company ("NIPSCO" or the "Company") as Manager, Major Projects & Resource Development. In this role, I am responsible for management of capital and operation and maintenance ("O&M") projects throughout NIPSCO's generation operations.

Q3. What is your educational background?

A3. I received a bachelor degree in Mechanical Engineering from Western Michigan University in 1980, and I am a Licensed Professional Engineer in the State of Indiana.

Q4. Please describe your professional experience.

A4. I began my employment with NIPSCO in 1981 in the Results Department. My experience includes various technical and management positions in Electric Production prior to my promotion to Operations Manager of Bailly Generating Station in 2000, Compliance Projects Manager in March 2002 and Manager, Major Projects and Resource Development in June 2006.

Q5. Have you previously testified before this or any other regulatory commission?

A5. Yes, I have testified before the Indiana Utility Regulatory Commission ("Commission") on environmental matters for NIPSCO in several proceedings including Cause Nos. 42150, 43144 and 43371.

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to: (1) describe NIPSCO's generation fleet and changes to that fleet, including the retirement and demolition of the D. H. Mitchell Generating Station ("Mitchell") and Michigan City Generating Station ("Michigan City") Units 2 and 3; (2) support an operation and maintenance ("O&M") expense adjustment to reflect increases in contract labor costs shown on Petitioner's Exhibit LEM-2; and (3) explain adjustments to NIPSCO's environmental cost recovery mechanisms.

I. NIPSCO'S GENERATION FLEET

Q7. Are you generally familiar with NIPSCO's generating facilities?

A7. Yes, I am.

Q8. Please generally describe NIPSCO's generation fleet.

A8. The NIPSCO generating facilities have a total capacity of 2,787 megawatts ("MW") and consist of six (6) separate generation sites, including the Company's R.M. Schahfer Generating Station, Michigan City, Bailly Generating Station, Mitchell and two (2) hydroelectric generating sites near Monticello, Indiana. Of the total capacity, 92.4% is from coal-fired units, 7.3% is from natural gas-fired units and 0.3% is from hydroelectric units. Petitioner's Exhibit PWP-2 provides a summary of the generating facilities operated by NIPSCO.

Q9. Has NIPSCO made any capital investment in generation facilities not included in test year results?

A9. Yes. As NIPSCO Witness Bradley K. Sweet explains, on May 30, 2008, NIPSCO acquired Sugar Creek Power Company, LLC which then owned a 535 MW combined cycle gas turbine ("CCGT" or "Sugar Creek") located near Terre Haute, Indiana. Sugar Creek Power Company, LLC was then merged into NIPSCO. As a result of this transaction, NIPSCO now owns the CCGT. Sugar Creek is configured with two combustion gas turbines ("CTs") and one steam turbine generator ("STG"). Sugar Creek has the ability to interconnect with either the Midwest Independent Transmission System Operator, Inc. (the "Midwest ISO") or the PJM Interconnection, LLC ("PJM").

Q10. Did NIPSCO receive a Certificate of Public Convenience and Necessity ("CPCN") from the Commission prior to acquiring Sugar Creek?

A10. Yes. The Commission granted NIPSCO a CPCN for the acquisition of Sugar Creek in its May 28, 2008 Order in Cause No. 43396 (the "CPCN Order").

Q11. Can NIPSCO determine the O&M expenses associated with Sugar Creek?

A11. Yes. NIPSCO has access to the 2007 Sugar Creek historical O&M and variance reports from May through December, 2007 and the 2008 annual budget. The 2007 (8 months) actual O&M was $5,378,997 compared to a budget of $5,770,339. The 2008 Sugar Creek annual budget includes budgeted O&M expense of $7,677,900. I have reviewed this information and believe it to be reliable. Using 2007 data, NIPSCO has calculated the projected non-fuel O&M expense Sugar Creek will incur for the first twelve month period the unit is dispatched into the Midwest ISO. The projected O&M cost to operate Sugar Creek from June 1, 2010 through May 31, 2011 is $9,388,421. Attached to my testimony as Petitioner's Exhibit PWP-3 is a breakdown of the O&M costs for Sugar Creek.

Q12. How did NIPSCO calculate the O&M costs for Sugar Creek for the twelve months commencing June 1, 2010?

A12. NIPSCO used the historical O&M costs for Sugar Creek and input that data into PROMOD to develop the O&M expenses for this period. PROMOD is a computer program that uses historic operating costs, unit heat rate and expected market conditions to develop generation projections for each NIPSCO unit. The use of PROMOD allows NIPSCO to account for the variable O&M cost difference between Sugar Creek's dispatch into PJM and the Midwest ISO. The O&M cost uses historical data for the fixed costs and adds a five year amortization of the gas turbine Long Term Service Agreement ("LTSA") overhaul costs ($1,524,405).

Q13. Please explain the LTSA for Sugar Creek.

A13. The LTSA is a contract with General Electric International, Inc. to perform routine maintenance on the Sugar Creek facility turbines and generators. The LTSA was executed prior to NIPSCO's acquisition of the Sugar Creek facility and NIPSCO assumed the LTSA as part of the merger. Major maintenance is performed at intervals determined by the number of operating starts and hours. NIPSCO's due diligence of the Sugar Creek facility compared the confidential prices of the LTSA to market prices and determined the LTSA has favorable economic terms.

Q14. Did NIPSCO experience operational constraints in 2007 that reduced the operating hours of any of its generating units?

A14. Yes. In 2007, NIPSCO's generation fleet experienced three unusually long outages. Unit 7 experienced a planned outage to combine maintenance with the installation of environmental control equipment. The Unit was scheduled for the replacement of the boiler cyclones, various boiler pressure parts, a turbine overhaul and the installation of a Selective Catalytic Reduction ("SCR") system for NOx reduction. Due to the amount of work that was scheduled, two outages totaling 25 weeks were required to prevent interference among projects. Installation of an SCR at Unit 7 is a one time event that is not anticipated to occur again. Unit 10 experienced a forced outage on February 1, 2007. This outage was caused by a failure of the rotor stub shaft bolting resulting in extensive turbine damage. This outage lasted through the end of 2007 and into 2008 due to difficulties obtaining replacement components. Unit 16A also experienced a long forced outage beginning August 1, 2007. The outage was caused by a failure of blade locking pins that caused extensive damage to the compressor section of the unit. Damage of this kind is not typical and would not be something I would expect to occur in the future. The outage continued throughout the end of the 2007 year and into 2008. Due to these unusual constraints, the 2007 operational availability for Units 7, 10 and 16A should be adjusted as described in Mr. Sweet's testimony.

II. DEMOLITION OF CERTAIN UNITS

Q15. What generation facilities is NIPSCO retiring?

A15. NIPSCO is retiring Mitchell and Michigan City Units 2 and 3.

Q16. Please describe Mitchell.

A16. Mitchell has four coal fired units which range in age from 38 to 52 years old. At shutdown in 2002, Units 5, 6, and 11 burned low sulfur sub-bituminous coal from the Powder River Basin in Wyoming. Unit 4 had the capability to burn either natural gas or Powder River Basin coal. The net capacity of the four coal fired units totaled 485 MW. As indicated in Mr. Sweet's testimony, Units 4, 5, 6 and 11 were indefinitely shutdown in January 2002. Unit 9 is a natural gas combustion turbine capable of 17 MW of output.

Q17. Why is NIPSCO retiring Mitchell?

A17. Mr. Sweet describes in more detail the reasons NIPSCO no longer intends to operate Mitchell. The restart of the shutdown Mitchell units was considered in NIPSCO's 2007 Integrated Resource Plan ("IRP") modeling as a supply-side option. The IRP suggested the Mitchell restart options should be abandoned in lieu of purchasing one or more CCGTs because of the $587,500,000 cost to restart Mitchell. As indicated in Table 7-8 (page 145) of the 2007 NIPSCO IRP, the New Energy "Strategist" Model never selected a Mitchell reactivation option as a low-cost supply-side resource in the next 20 years. NIPSCO will retire Mitchell, demolish the facilities and remediate the site to industrial condition.

Q18. What is generally involved in demolishing and remediating Mitchell?

A18. As described in the demolition cost study prepared by Burns & McDonnell and submitted as Petitioner's Exhibit VFR-3, Mitchell's demolition will include removal of equipment at the site, as well as any building structures, but leaving the below grade piping and wiring in place. Foundations will be filled to grade and the coal pile and ash ponds will be covered with soil and seeded. Burns & McDonnell estimates that remediating Mitchell will take approximately 30 months.

Q19. Please describe the Michigan City Units 2 and 3?

A19. The two natural gas fired units at Michigan City station range in age from to 57 to 58 years old. The net capacity of the units totaled 120 MW. The boilers for Units 2 and 3 were coal-fired until 1988 when the operation was limited to natural gas only to reduce SO_2 emissions from the plant. As indicated by Mr. Sweet, Michigan City Unit 2 and 3 were indefinitely shutdown in June 2005 due to the condition of the boilers.

Q20. Why is NIPSCO retiring the Michigan City Units 2 and 3?

A20. Mr. Sweet explains why NIPSCO is retiring Michigan City Units 2 and 3. In general terms, NIPSCO has determined the units are at the end of their useful life due to extensive tube corrosion damage to boiler walls and cyclones. Additionally, the turbines and auxiliary systems have extensive wear due to their 50 plus years of service. NIPSCO will retire Units 2 and 3 and demolish the facilities in the manner described in the Burns & McDonnell demolition studies marked as Petitioner's Exhibit VFR-6.

Q21. What is generally involved in demolishing the Michigan City Units 2 and 3?

A21. As described in the Burns & McDonnell demolition study, the demolition of Units 2 and 3 includes removal of all associated equipment, piping, wiring and HVAC equipment not necessary for continued operations of Michigan City Unit 12. The shell of the building would remain in-place. Burns & McDonnell estimates demolishing Michigan City Units 2 and 3 will take approximately 22 months.

Q22. Will any Michigan City units remain in service after the retirement of Units 2 and 3?

A22. Yes. Michigan City Unit 12 will remain a supply-side resource for NIPSCO and will remain in service.

Q23. Are you familiar with the information relied upon by Burns & McDonnell in the preparation of the demolition studies and sponsored by Mr. Ranaletta?

A23. Yes, I am. The Burns & McDonnell demolition cost studies sponsored by Mr. Ranaletta's testimony rely on NIPSCO site and equipment drawings, historic contamination associated with Solid Waste Management Units and asbestos remediation estimates prepared by NIPSCO's asbestos contractor Insulco. Based upon my knowledge and review of these documents, this information can be relied upon by Burns & McDonnell in the preparation of its demolition cost studies.

III. GENERATION O&M EXPENSE ADJUSTMENT

Q24. Are you supporting any adjustments to O&M for generation?

A24. Yes. I recommend an upward adjustment to O&M generation maintenance expense to reflect increases in contract labor costs.

Q25. Have you provided the data to NIPSCO Witness Linda E. Miller to support her adjustment for this expense?

A25. Yes. At my direction and under my supervision, my staff provided this information to Ms. Miller reflected in Petitioner's Exhibit LEM-2.

Q26. What contract labor costs does NIPSCO incur in its generation operations?

A26. NIPSCO contracts with outside companies to provide labor for many generation projects. Manpower requirements peak during unit outages and require outside workers to complete the many O&M projects in a reasonable time frame.

Q27. Why has NIPSCO's contract labor cost increased since the close of the test year?

A27. Competition for skilled workers in Northwest Indiana has increased which has generated challenges in sourcing contract labor. For example, the BP refinery in Whiting, Indiana will be implementing a major expansion over the next several years which will require a contract work force that is expected to peak at approximately 4,000 people. This project will draw from the same skilled labor force that NIPSCO utilizes to do the work in its generating facilities. This heightened competition for skilled labor force results in NIPSCO being unable to engage the most experienced labor, which results in more time and cost to fulfill equivalent work tasks.

Q28. Do you believe the current skilled labor shortage will abate in the near future?

A28. No, I do not. NIPSCO's experience in engaging contract labor is that the cost continues to increase annually. This experience is supported by studies I have reviewed. The

Federal Energy Regulatory Commission ("FERC") recently instructed its Staff to investigate the upward pressure on electricity prices. The FERC Staff reported its findings on June 19, 2008. I have attached a copy of that report to my testimony as Petitioner's Exhibit PWP-4 and will refer to this report hereafter as the "FERC Report". The FERC Report (p. 10) shows that the average yearly labor increase in the Electric Industry over the last 8 years is 3.375%. A report from the Brattle Group entitled the Rising Utility Construction Costs (pp. 20-21), which I have also attached to my testimony as Petitioner's Exhibit PWP-5, substantiates this conclusion.

Q29. What level of increased costs are you proposing for the adjustment?

A29. The adjustment I propose is based on the average yearly labor increase in the Electric Industry over the last 8 years noted by the FERC Report and the Rising Utility Construction Costs from the Brattle Group. These studies show annual labor increases of 3.375%. Because NIPSCO intends to use, at least, the same amount of contracted O&M labor in 2008 as it did in 2007 ($29,827,075), I multiplied this annual cost increase by the amount of 2007 contracted O&M labor. This results in a cost increase for contracted labor of $1,006,664 that should be added to NIPSCO's actual costs for 2007.

IV. AMENDMENTS TO NIPSCO'S ENVIRONMENTAL COST RECOVERY MECHANISMS

Q30. Are you familiar with NIPSCO's environmental compliance cost recovery filings?

A30. Yes. I have previously testified in support of NIPSCO's implementation of the ratemaking treatment for qualified pollution control property ("QPCP"), as authorized by the Commission in its Order entered November 26, 2002, in Cause No. 42150 ("Order") and its Order entered, July 3, 2007, in Cause No. 43188 ("CAIR/CAMR Order"). In addition, I have testified in support of NIPSCO's proposed rate adjustments for recovery of operating, maintenance and depreciation expenses connected with the operation of its QPCP that is in service, as authorized by the Commission in its Order. My testimony has related to NIPSCO's Environmental Cost Recovery Mechanism ("ECRM") and its Environmental Expense Recovery Mechanism ("EERM"), which are applicable to NIPSCO electric utility customers.

Q31. Is NIPSCO proposing any changes in its ECRM or EERM?

A31. Yes. NIPSCO is proposing to clarify that its ECRM and EERM are designed to recover costs associated with compliance with current and anticipated air regulations on a semi-annual basis, including recovery through its EERM of emission allowance purchase costs and the crediting of revenues from the sale of any emission allowances. NIPSCO Witness Frank A. Shambo discusses the regulatory policies driving these changes.

Q32. Does this conclude your prepared direct testimony?

A32. Yes it does.

VERIFICATION

I, Philip W. Pack, Manager, Major Projects & Resource Development for NIPSCO, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Philip W. Pack

Philip W. Pack

Date: August 6, 2008

INDS01 PJS 1040166v3

Petitioner's Exhibit PWP-2
Northern Indiana Public Service Company
Cause No. 43526

SUMMARY OF NIPSCO
GENERATING FACILITIES

R. M. SCHAHFER GENERATING STATION

The R. M. Schahfer Generating Station is located on an approximately 3150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. This station is the newest and largest of the Company's generating stations and provides over 60% of NIPSCO's electric generation capacity. Its four base-load and two peaking units came on-line over an eleven-year period ending in 1986. The units are equipped with various environmental control technologies, including Flue Gas Desulfurization (FGD) to reduce sulfur dioxide (SO_2) emissions and Selective Catalytic Reduction (SCR), Low NOx Burners (LNB) and Overfire Air (OFA) systems to reduce nitrogen oxide emissions as required by law. Installation of a new Low NOx Burner with Over Fire Air system is planned for Unit 15 in 2008. Also, Units 14 and 15 burn low-sulfur coal to minimize sulfur dioxide emissions. The individual unit characteristics of the R. M. Schahfer Generating Station are as follows:

R. M. SCHAHFER GENERATING STATION UNIT INFORMATION

	UNIT 14	UNIT 15	UNIT 17	UNIT 18	UNIT 16A	UNIT 16B
NET LOAD						
MIN (MW)	250	200	125	125	----	----
MAX (MW)	431	472	361	361	78	77
BOILER	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
BURNERS	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	--------	--------
MAIN FUEL	COAL	COAL	COAL	COAL	GAS	GAS
TURBINE	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
FRAME	BB44R	G2	BB243	BB243	D501	D501
IN-SERVICE	12/31/76	10/31/79	4/28/83	2/14/86	12/31/79	12/31/79
ENVIRONMENTAL CONTROLS	SCR OFA	LNB	FGD LNB OFA	FGD LNB OFA	---	---

Petitioner's Exhibit PWP-2
Northern Indiana Public Service Company
Cause No. 43526

BAILLY GENERATING STATION

The Bailly Generating Station is located on a 100-acre site on the shore of Lake Michigan in Porter County, Indiana. The stations two base-load and one peaking units came on-line over a six-year period ending in 1968. The units are equipped with various environmental control technologies, including Flue Gas Desulfurization (FGD) to reduce sulfur dioxide (SO_2) and Selective Catalytic Reduction (SCR) and Overfire Air (OFA) systems to reduce nitrogen oxide emissions as required by law. The individual unit characteristics of the Bailly Generating Station are as follows:

BAILLY GENERATING UNIT INFORMATION

		UNIT 7	UNIT 8	UNIT 10
NET LOAD				
	MIN (MW)	100	200	---
	MAX (MW)	160	320	31
BOILER		Babcock & Wilcox	Babcock & Wilcox	----
BURNERS		4 Cyclone	8 Cyclone	----
MAIN FUEL		COAL	COAL	GAS
TURBINE		General Electric	General Electric	Westinghouse
FRAME		D6	G2	W301G
IN-SERVICE		11/30/62	7/31/68	11/30/68
ENVIRONMENTAL CONTROLS		FGD OFA	FGD SCR OFA	 ---- ----

MICHIGAN CITY GENERATING STATION

The Michigan City Generating Station is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. Michigan City has one base-load and two gas-fired steam units. Units 2 and 3 are currently unavailable and are on an extended forced outage and due to the operating uncertainty of the two units, each has been removed from the list of potential supply side resources available in 2008 and thereafter. Unit 12 is equipped with Selective Catalytic Reduction (SCR) and Over-Fire Air (OFA) systems to reduce nitrogen oxide emissions as required by law. Unit 12 also burns low-sulfur coal to minimize sulfur dioxide emissions. The individual unit characteristics of the Michigan City Generating Station information is as follows:

MICHIGAN CITY GENERATING UNIT INFORMATION

		UNIT 2	UNIT 3	UNIT 12
NET LOAD				
	MIN (MW)	0	0	250
	MAX (MW)	0	0	469
BOILER		Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox
BURNERS		2 Cyclone	2 Cyclone	10 Cyclone
MAIN FUEL		GAS	GAS	COAL
TURBINE		Westinghouse	Westinghouse	General Electric
FRAME		--	--	G2
IN-SERVICE		11/21/50	10/23/51	5/31/74
ENVIRONMENTAL		--	--	SCR
CONTROLS		--	--	OFA

D. H. MITCHELL GENERATING STATION

The D. H. Mitchell Generating Station is located on a 100-acre site in the northwest corner of Gary, Indiana, directly north of the Gary Airport on the shore of Lake Michigan. Units 4, 5, 6 and 11 have been indefinitely shutdown since 2002. NIPSCO continues to operate Unit 9A, as required. The individual unit characteristics of the D. H. Mitchell Generating Station are as follows:

D. H. MITCHELL GENERATING STATION UNIT INFORMATION

(Station shutdown 1/02)

	UNIT 4	UNIT 5	UNIT 6	UNIT 11	UNIT 9
NET LOAD					
MIN (MW)	0	0	0	0	----
MAX (MW)	0	0	0	0	17
BOILER	Combustion Engineering	Combustion Engineering	Combustion Engineering	Babcock & Wilcox	----
BURNERS	4 Pulverizers	4 Pulverizers	4 Pulverizers	4 Pulverizers	--------
MAIN FUEL	COAL/GAS	COAL	COAL	COAL	GAS
TURBINE	General Electric	General Electric	General Electric	General Electric	General Electric
IN-SERVICE	12/6/56	5/30/59	9/24/59	5/31/70	12/1/66

NORWAY HYDROELECTRIC DAM

Norway Hydroelectric Dam is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has 4 generating units capable of producing up to 7,200 kW of electricity per hour. However, Norway Hydro output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydroelectric Dam are as follows:

NORWAY HYDROELECTRIC DAM INFORMATION

		UNIT 1		UNIT 3	UNIT 4
NET LOAD					
	MIN (kW)	---	---	---	---
	MAX (kW)	2,000	2,000	2,000	1,200
IN-SERVICE		1923	1923	1923	1923
MAIN FUEL		WATER	WATER	WATER	WATER

OAKDALE HYDROELECTRIC DAM

Oakdale Hydroelectric Dam is located along the Tippecanoe River near Monticello, Indiana. The dam creates Lake Freeman, approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale has 3 generating units capable of producing up to 9,200 kW. However, the Oakdale Hydro output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydroelectric Dam are as follows:

OAKDALE HYDROELECTRIC DAM
UNIT INFORMATION

		UNIT 1	UNIT 2	UNIT 3
NET LOAD				
	MIN (kW)	---	---	---
	MAX (kW)	4,400	3,400	1,400
IN-SERVICE		1925	1925	1925
MAIN FUEL		WATER	WATER	WATER

Summary

The table below provides the net capacity, type of fuel burned and in-service dates for each of NIPSCO's generating units currently in rate base.

Northern Indiana Public Service Company
Existing Generating Units

Unit	NDC (MW)	Type	Typical Fuel Burned	In-Service Date
Michigan City 2	0	Steam	Natural Gas	November 21, 1950
Michigan City 3	0	Steam	Natural Gas	October 23, 1951
Michigan City 12	469	Steam	Coal	May 31, 1974
Mitchell 4	0	Steam	Coal/Natural Gas	December 6, 1956
Mitchell 5	0	Steam	Coal	May 30, 1959
Mitchell 6	0	Steam	Coal	September 24, 1959
Mitchell 11	0	Steam	Coal	May 31, 1970
Mitchell 9A	17	Combustion Turbine	Natural Gas	December 1, 1966
Bailly 7	160	Steam	Coal	November 30, 1962
Bailly 8	320	Steam	Coal	July 31, 1968
Bailly 10	31	Combustion Turbine	Natural Gas	November 30, 1968
Schahfer 14	431	Steam	Coal	December 31, 1976
Schahfer 15	472	Steam	Coal	October 31, 1979
Schahfer 16A	78	Combustion Turbine	Natural Gas	December 31, 1979
Schahfer 16B	77	Combustion Turbine	Natural Gas	December 31, 1979
Schahfer 17	361	Steam	Coal	April 28, 1983
Schahfer 18	361	Steam	Coal	February 14, 1986
Norway	4	Hydro	N / A	June 8, 1923
Oakdale	6	Hydro	N / A	November 11, 1925
Subtotal	2,574	Steam		
Subtotal	203	Combustion Turbine		
Subtotal	10	Hydro		
TOTAL SYSTEM	2,787			

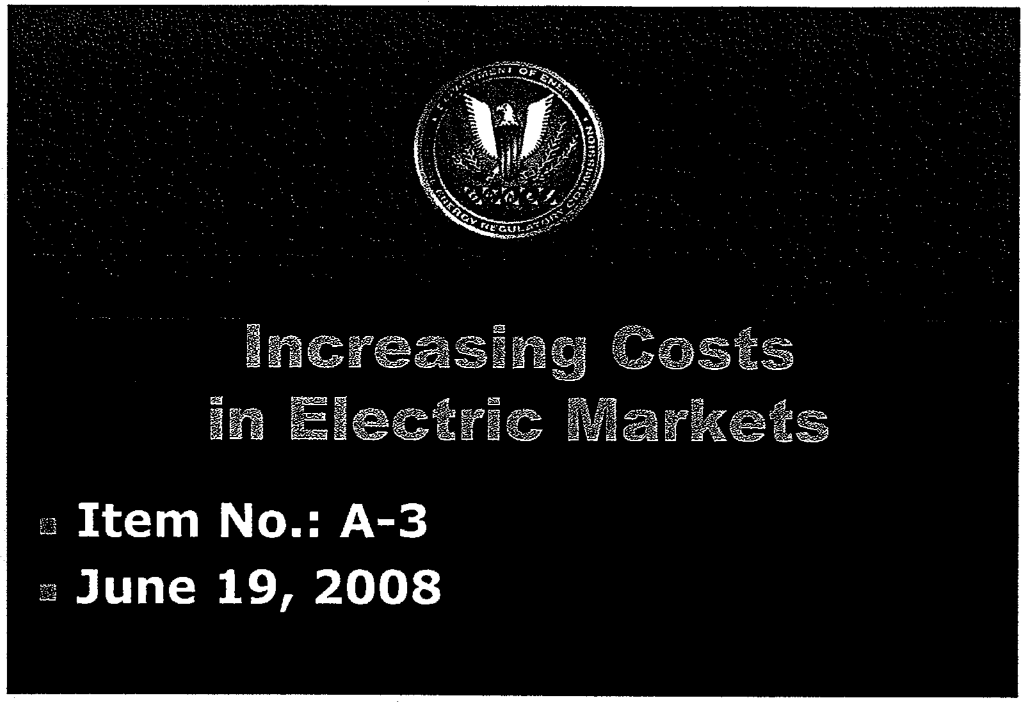
Sugar Creek Projected Operating Expenses for June 2010 thru May 2011
(all numbers in dollars)

	Fixed Costs	Variable Costs
Maintenance parts & service	460,968	525,693
Long term service agreement	1,524,405	2,838,851
Chemicals		208,410
Consumables	148,994	
Utilities	9,898	
Site Labor	2,537,694	
Employee and community relations	35,037	
Training and Travel	60,928	
Office Expenses	81,145	
Communications	62,277	
Vehicles	9,707	
Buildings and Grounds	45,931	
Subcontractor services	66,750	
Insurance	464,554	
Professional services	294,893	
Administrative	-	
Permits and emission fees	12,286	
Fixed & Variable Expenses	5,815,467	3,572,954
Total Expenses		9,388,421

Based on historical expenses and PROMOD projections into MISO

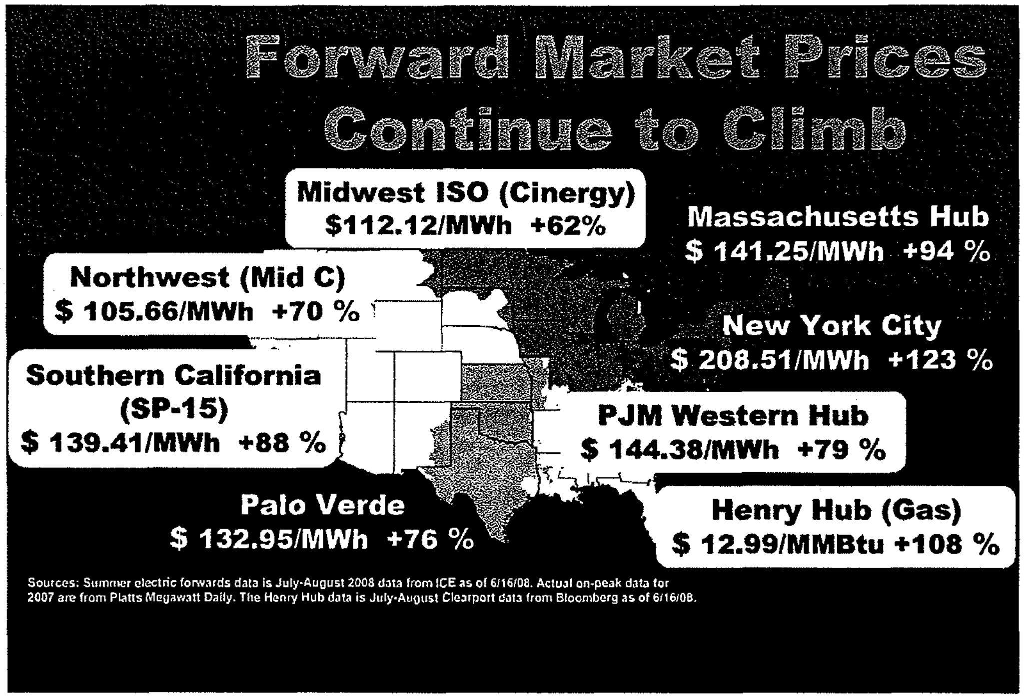
Fixed LTSA costs include combustion inspection & hot gas path inspection on GT1A
in May 2011and HGP inspection on GT1B in Nov. 2011
The fixed cost of these inspections is spread over 5 years from 2008 thru 2012

Petitioner's Exhibit PWP-4
Northern Indiana Public Service Company
Cause No. 43526



Mr. Chairman and Commissioners, good morning. I am here to present the Office of Enforcement's assessment of likely electricity costs in coming years. This presentation will be posted on the Commission's Web site today.

Petitioner's Exhibit PWP-4
Northern Indiana Public Service Company
Cause No. 43526



At last month's meeting, we reported that forward market prices for electric power are much higher than the prices we actually experienced last year. This trend is universal around the country. The slide shows the increases in forward prices for July and August as of this week. They have risen further during the last month as natural gas prices have continued to rise.

There is little reason to believe that this summer is unusual. Rather, it may be the beginning of significantly higher power prices that will last for years. The purpose of this presentation is to explain why that is so. The two major factors pushing the costs of electric generation higher are increased fuel costs and increased cost for new construction. These factors affect all parts of the country. That is, higher future prices are likely to affect all regions.

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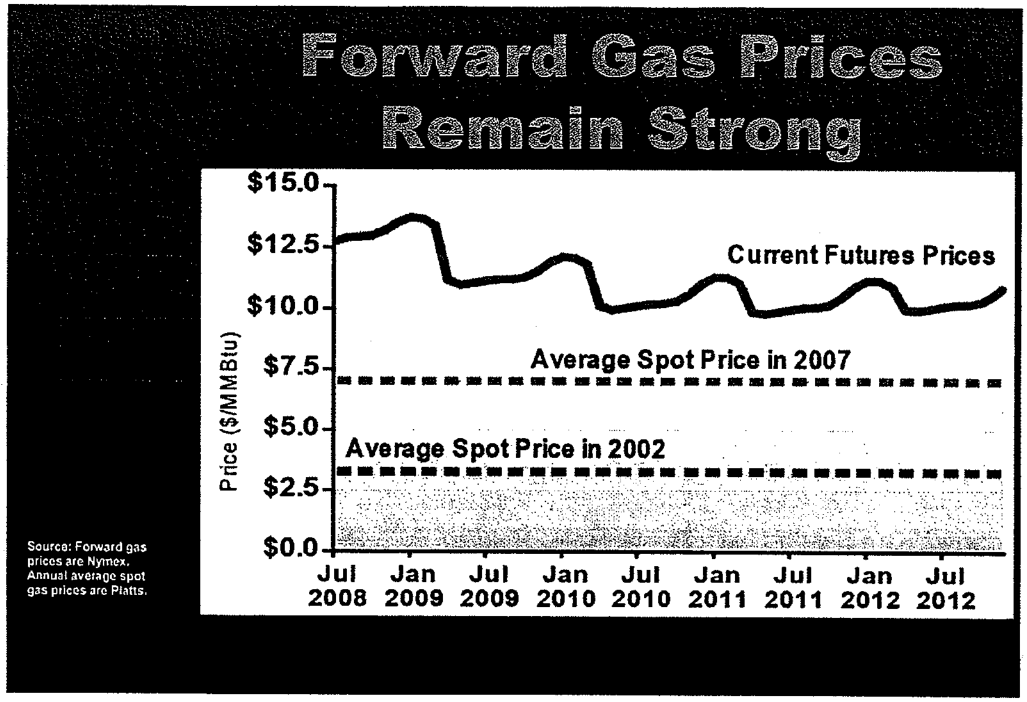

The primary reason for the electric power price increases this year is high fuel prices. All current market indications suggest that they will remain high. Let's look at natural gas, which often determines prices because it is so frequently on the margin. The slide shows futures prices for the next few years. The futures prices are somewhat lower for 2009 than for 2008. Even so, they are a good deal higher for all years than the prices people actually paid last year, and they are much higher than the prices many of us remember from earlier in the decade. The implication is that markets anticipate continuing high prices, even though they know that the United States has seen a significant increase in domestic natural gas production over the last year and a half. The anticipation of further high prices makes more sense when one considers the likely increase in gas demand for generation and the global nature of competition for LNG.

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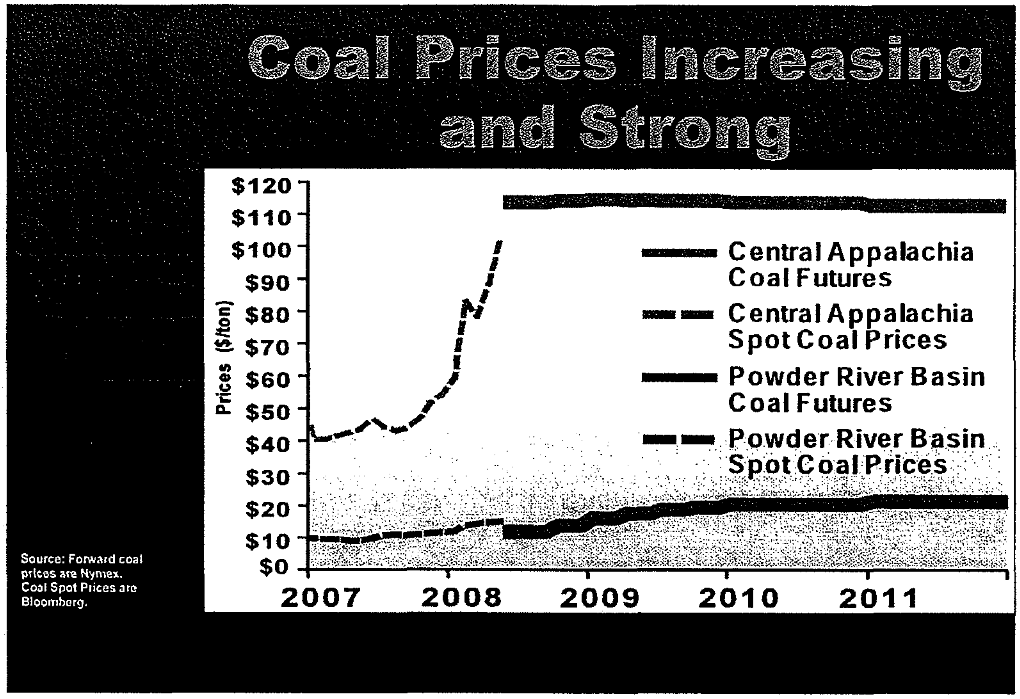

Natural gas is not the only important fuel in setting electric power prices. Coal still powers half of all power produced in the U.S. In some markets – the Midwest and the Southeast, for example – coal is often on the margin and plays a major role in setting average prices over time. The slide shows that the price of one key form of coal – Central Appalachian coal - has risen rapidly over the last year. Forward markets show continuing high prices for Central Appalachian coal for the next three years. This reflects, in part, the growing global market for coal and the relatively weak US dollar. Coal imports are becoming more costly and coal exports more profitable, both of which contribute to higher prices in the United States.

I should mention that other coal prices behave somewhat differently from Central Appalachian coal. For example, a majority of the overall cost for Powder River Basin coal comes from transportation rates and can be more difficult to see. Nonetheless, the implication of the prices we can see is that electric power prices are likely to increase even where coal is on the margin. This may take place somewhat differently from the way natural gas price increases flow through into power prices. Generally, companies buy coal under fairly long term contracts, so there may be a lag before the higher prices show their full effects. But the effects are coming.

Net Natural Gas Generation by Region

(TWh)

Region	2000	2007	Difference
Northeast	66.3	103.9	37.6
RFC	41.0	64.5	23.5
SERC	86.9	150.5	63.6
FRCC	42.0	96.7	54.7
ERCOT	155.9	163.3	7.4
Midwest	44.2	62.8	18.5
WECC-Rockies and SW	28.1	77.6	49.5
WECC-CA and NW	115.4	129.7	14.4

Source: Derived from Energy Velocity (differences due to rounding).

While both natural gas and coal prices have increased rapidly, natural gas is increasingly important in every region of the country. The slide shows that even in regions where coal has historically dominated – most noticeably in SERC– natural gas usage has grown substantially since 2000, up 63.6 TWh in 2007, more than in any other region. Noticeable increases also occurred in FRCC, which has flexibility to burn either gas or oil at many facilities, and also in the Rockies and Southwest where demand continues to grow considerably.

NERC Net Load Projections through 2016

Region	Total Difference (GW)	Percent Change
Northeast	9.7	17
RFC	23.2	13
SERC	28.2	14
FRCC	7.1	15
ERCOT	14.7	24
Midwest	17.2	21
WECC-Rockies and SW	7.6	25
WECC-CA and NW	10.9	10
Total	108.8	14

Source: Derived from NERC 2007 Long Term Reliability Assessment, Oct. 2007 and NERC data request, June 2008.

The second major factor that will put upward pressure on electric power prices is the increasing cost of new construction. This effect is particularly important because the country is entering a period when we will need to make substantial new investments, especially in generation.

Natural gas fueled most of the last great wave of generation investment, which occurred between 1995 and 2004. In recent years, demand in most regions has gradually caught up with the capacity built around 2000. Looking forward, demand will continue to grow, and the need for new capacity will become ever more acute and ever more widespread. The slide shows NERC's expectation of peak net load growth in different regions for the next 10 years. We at the Commission are not in the business of forecasting, so I would just say this: There are legitimate reasons to be unsure about exactly how much new generation the country will need in the coming years. For one thing, higher prices will themselves discourage some power demand. Nonetheless, a significant level of demand increase seems virtually inevitable. So will be the need to build more capacity.

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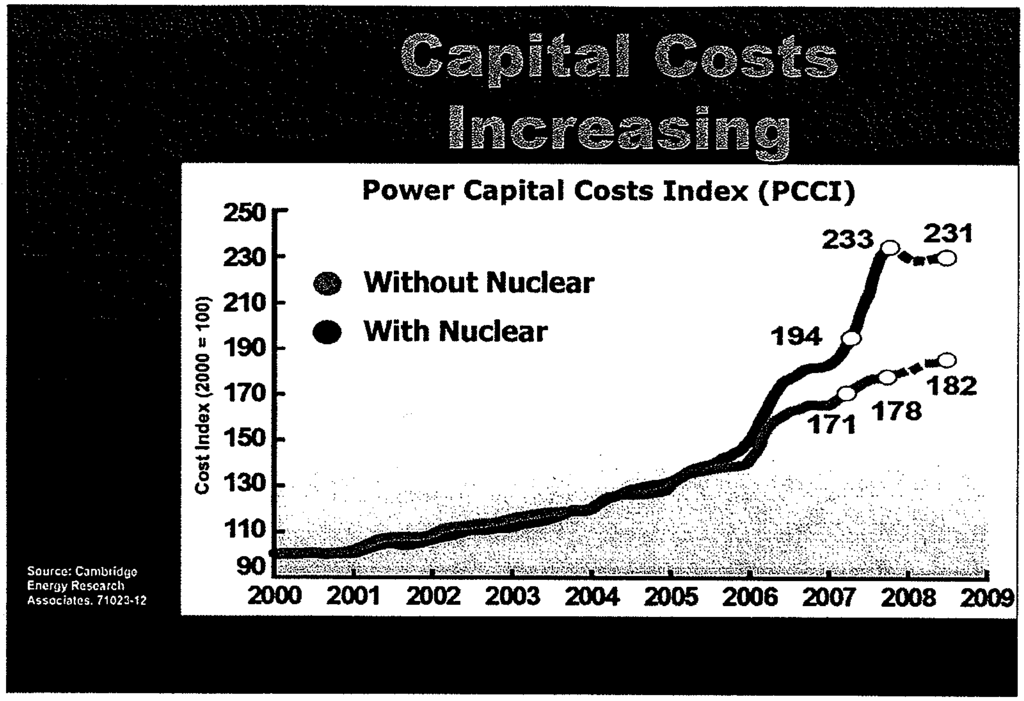

The need for new generation is important because new construction is becoming more expensive – quite aside from fuel price increases. Cambridge Energy Research Associates – CERA – produces an index of costs for the main inputs that go into building new generating plants. The slide shows how that index has almost doubled since 2003. The increase in nuclear plant inputs has risen even faster. Much of this cost increase results from rising global demand for basic materials. Part of it also comes from shortages of people to do key engineering and construction jobs. In any case, the implication is that, we will pay more, not less, for the next round of construction.

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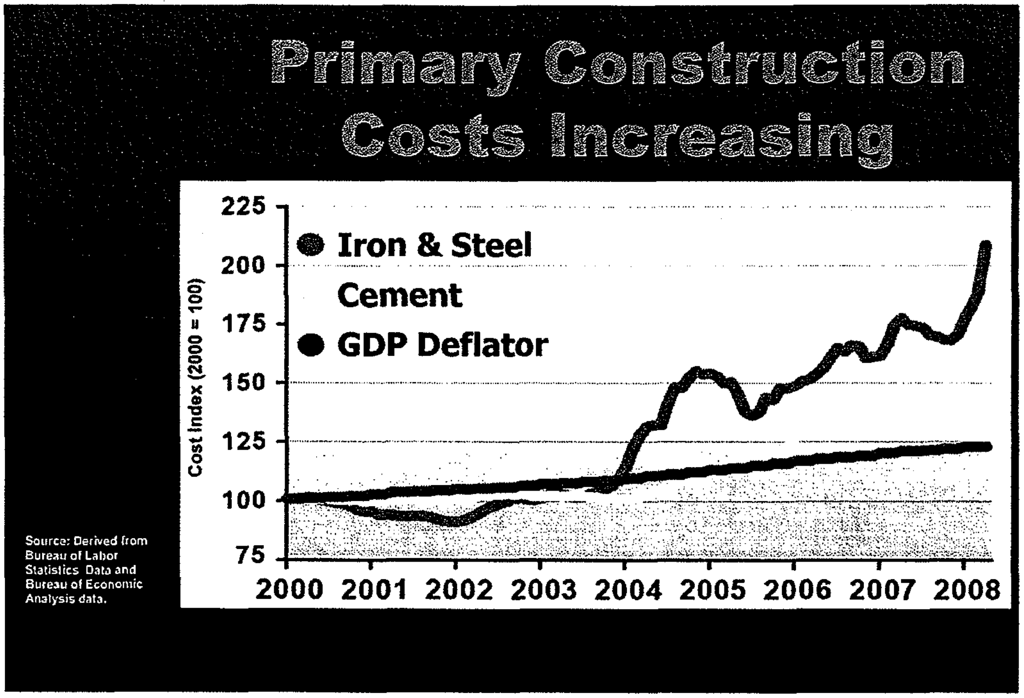
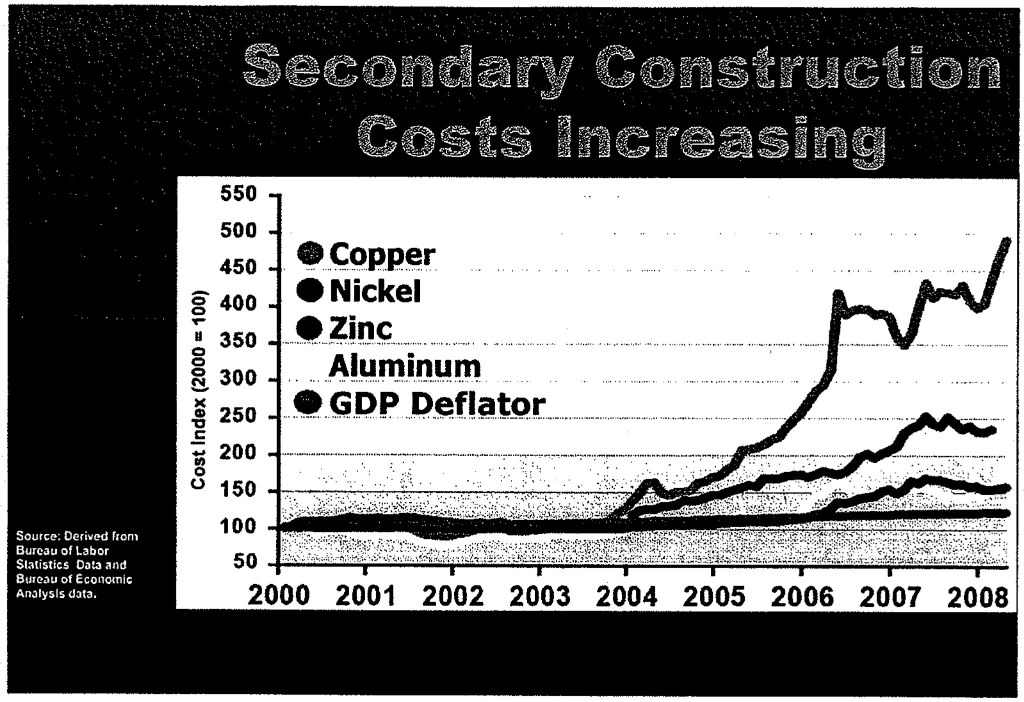


Let's look at some of the reasons that CERA's index is rising so rapidly. The slide shows two of the primary construction materials for electric generating plants – concrete is on the blue line and iron and steel on the red line. As you can see, the prices of both have been rising recently – especially steel, which is now more than twice as expensive as it was four years ago. Rising costs for iron and steel will also affect fuel prices for the power industry. For example, natural gas wells and pipelines both use substantial amounts of steel, so natural gas costs will also reflect rising iron and steel prices.



Of course, new generating plants require many other basic commodities. The slide shows the pricing for four key metals that go into generators. As you can see, all of these metals are increasing in price. The one that stands out is copper, up more than five times over the past four years. Indeed, copper is now so valuable there are reports of copper thieves cutting live cables to steal the metal.

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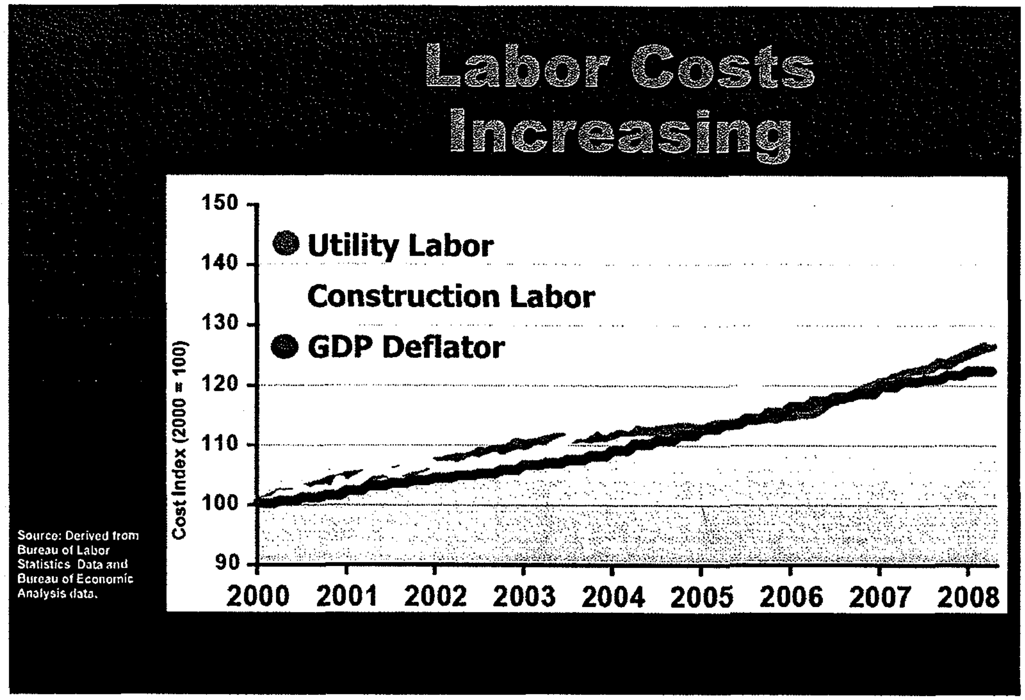
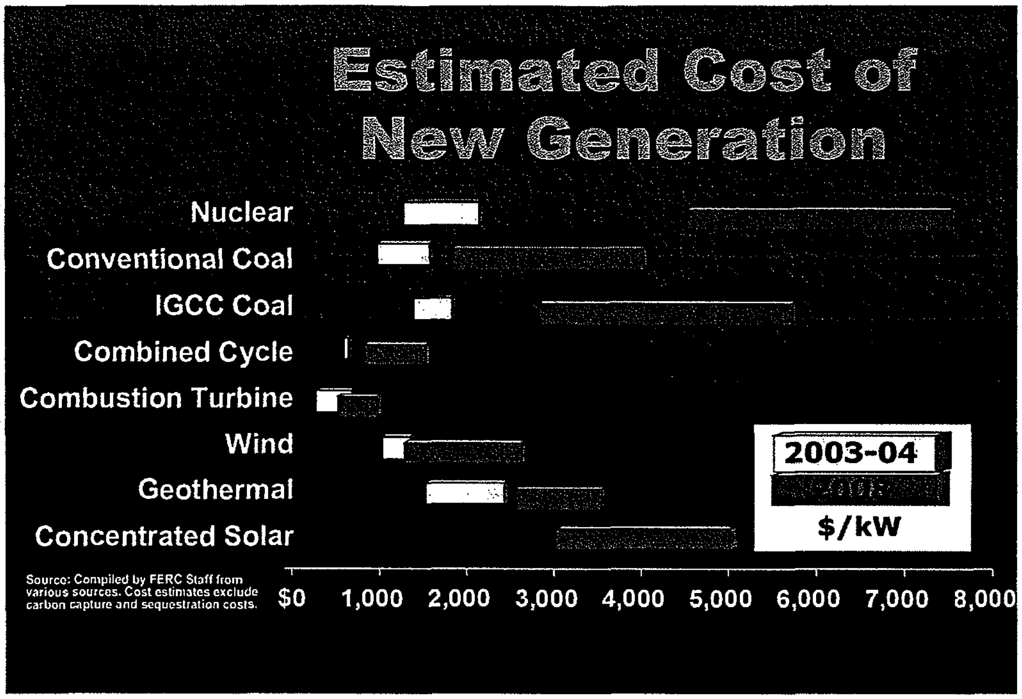


Labor costs are also increasing. Perhaps the most frequently cited labor shortage is that for nuclear engineers. It has been a full generation since the nation built its last nuclear plant. Most of the engineers who worked on those plants are near retirement – and many have moved on to other occupations. In fact, the labor shortages are more widespread than just nuclear engineers. The slide shows that there has been about a 27% nominal change in average hourly earnings for both construction labor generally and for non-construction utility labor since 2000, outpacing inflation by over 4% for the same period.

In practice, the American labor market is quite responsive to market forces, so short-term labor shortages tend to be self-correcting over the mid-term. Still, there is no quick way to force several years of education into six months, or decades of experience into a year or two.



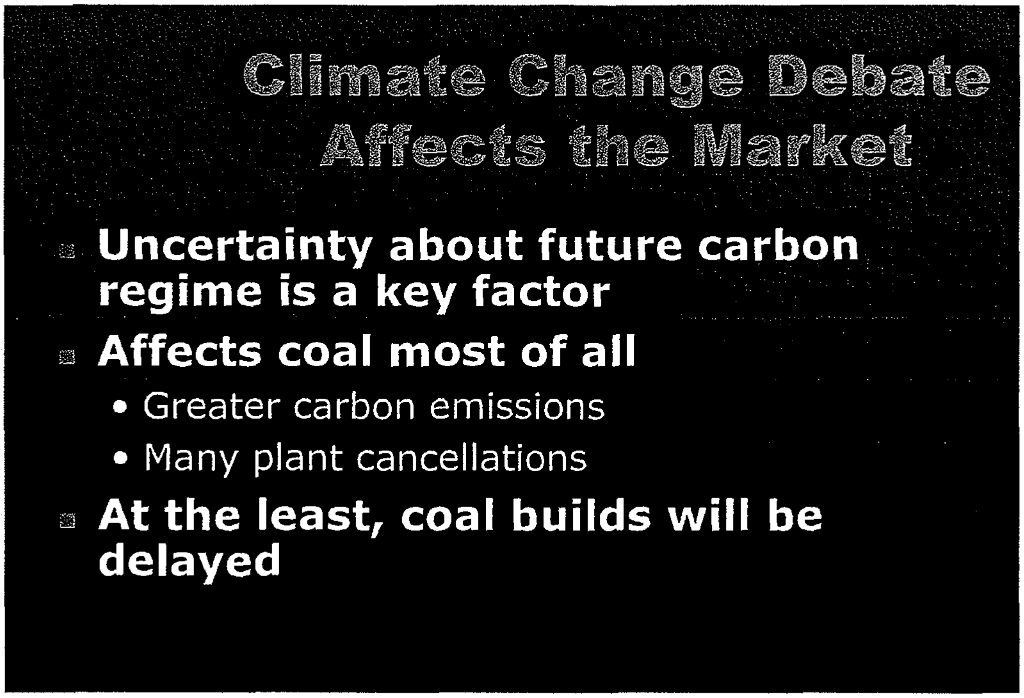
What do all these cost increases mean for the cost of building a new generating plant?

No one knows precisely. It's difficult to get consistent and trustworthy numbers about plant costs, both because they are commercially sensitive and because the assumptions behind them vary greatly. The numbers reflected on the slide come from a variety of sources and include different assumptions about, for example, location or exactly what facilities are included in the estimate. To take one example: Two recent nuclear procurements in South Carolina and Georgia produced cost estimates of $5,100 and $6,400 per kW, respectively, for the same technology. We have been told that most of the difference may be due to different uses of Allowances for Funds Used during Construction – AFUDC.

Despite the difficulties in being precise, the slide represents a good general indication of how capital costs have been changing. If anything, the cost estimates may be lower than the final costs of projects, if input costs continue to rise.

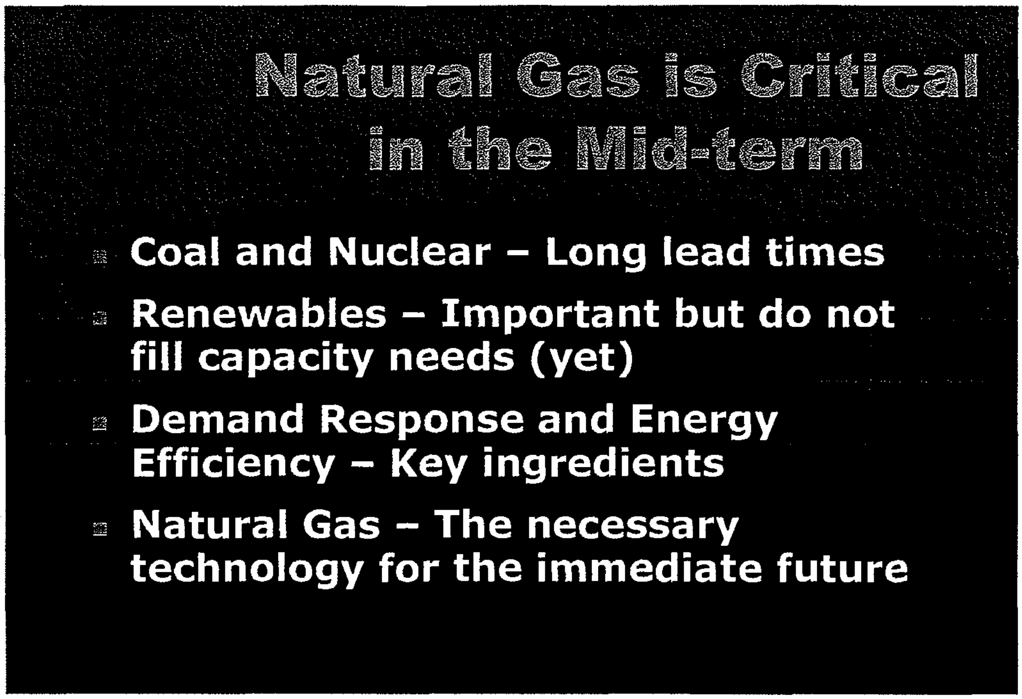
It's also important to remember that these cost estimates cover only capital costs. They do not include fuel costs, which as we've seen earlier will be a large factor for both natural gas and coal-fired plants. To the extent that plants do not have major fuel costs - they may be more competitive over their life cycles than would be suggested just looking at the capital costs. That would affect renewables and, to a degree, nuclear plants.

Similarly, these estimates generally do not include a full accounting of major risk factors, especially those affecting coal and nuclear plants. Both of these technologies have long lead times. That increases the chance that market conditions will change before they are complete and adds to the financial risk of building them. Nuclear plants also have risks associated with both decommissioning and waste fuel disposal. And coal plants have risks associated with the future treatment of greenhouse gases. Of course, relatively new technologies like wind and the new approaches to nuclear also have some risks, simply because they do not have the same track record of more mature technologies.



Climate change has become an increasingly urgent national issue. The debate over how to address carbon dioxide emissions is lively and has already affected how companies think about investments. Until recently, rising natural gas prices made coal plants attractive. However, the national uncertainty about carbon policy has made investing in coal plants more risky. Without carbon capture or sequestration, coal unit emit about four times as much carbon as natural gas combined cycle units per MWh. Since January 2007, 50 coal plants have been canceled or postponed. Only 26 remain under construction.

Whatever the eventual result of the climate change debate, costs of producing power from both coal and natural gas are likely to increase. Moreover, as long as future climate change policy is unclear, market participants will have a considerable disincentive to invest in coal plants. Even when the issues are resolved, it remains an open question how competitive coal-fired generation will be, and it would take another four to eight years to build new coal-fired capacity.



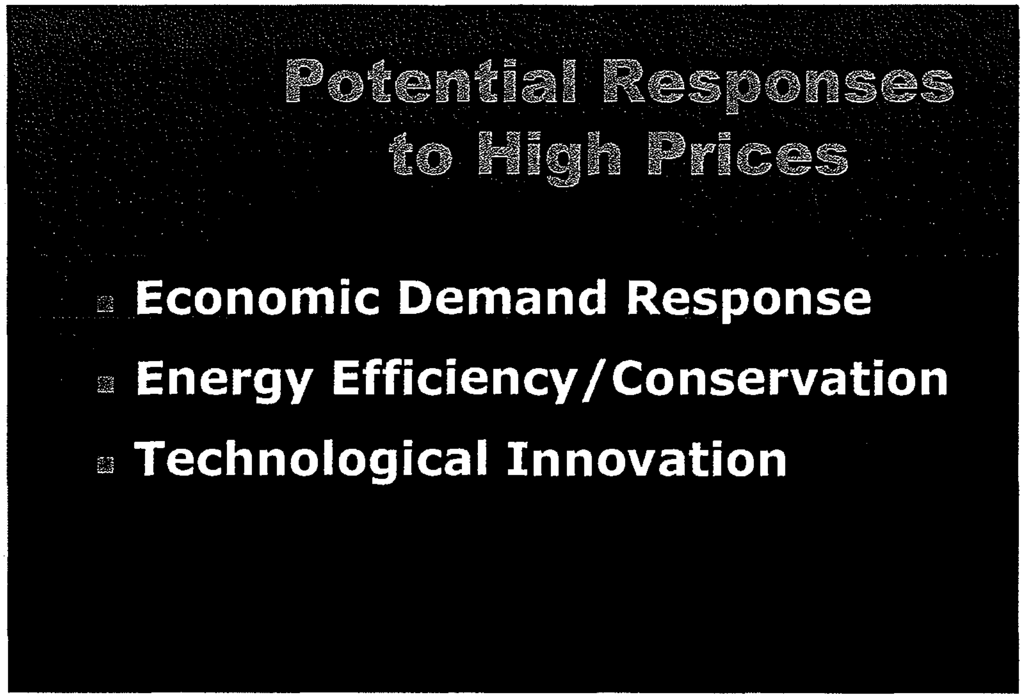
Over the long run, the nation can meet its increasing need for generation in several ways. But for the next few years, the options are more limited, and natural gas will be crucial.

The lead times for both nuclear and coal units mean that they will not supply a significant amount of new capacity for nearly a decade.

Most people expect renewables to supply an increasing proportion of the nation's power. For the next few years, wind will almost certainly account for a large share of generation investment and will account for a growing share of overall generation. Wind power has no fuel costs, and so will generally operate when available. However, wind is a variable, weather-dependent resource. As a result, it will not make up as strong a share of the Nation's capacity needs over the next few years. Other renewables are becoming more competitive. Geothermal power is already an important resource in the west, and concentrated solar is becoming economically attractive in desert areas like the Southwest. But these sources are likely to remain relatively small in the national picture over the next few years.

Both demand response and energy efficiency will be important – I'll talk more about them on the next slide – but they are unlikely to eliminate the need for new capacity.

Overall, the most likely outcome is that natural gas will continue to be the leading fuel for new capacity over the next half decade. For example, the consulting firm, Wood Mackenzie estimates that in a carbon constrained environment, gas consumption for power will increase by 69 % by 2017. That's in addition to the 55% increase we've seen since 2000.



Over the years, we have learned repeatedly that people respond to prices. In the case of electric power, this is likely to take several forms.

First, there is likely to be more demand response. In the simplest terms, high prices at peak will lead some customers – both businesses and others – to prefer to save their money rather than use power. In fact, the first round of demand response may be both the cheapest and fastest way to improve capacity margins on many systems. The best cost estimates for the first rounds of demand response suggest that it should be available for about $165/kW, far less than any generation side options. The results of ISO-NE's first Forward Capacity Market auction last year corroborates the economic importance of demand response - 7.4 % of the accepted bids were for demand response. However, there are impediments that limit the full use of demand response. For example, most customers do not have the option to respond directly to real-time prices. As a result, they are unlikely to reduce peak consumption as much as they might prefer to if they could take advantage of the price.

Second, customers are likely to be more energy efficient. While few customers see real-time prices, most get an average price over a month. As a result, high prices give them considerable incentive to reduce their overall consumption of power – though no more at peak than at other times. That is, energy efficiency is essentially a substitute for baseload capacity, while demand response is a substitute for peaking capacity. Energy efficiency is also likely to be economically important. Cost estimates show that the first round of energy efficiency may be available for about 3 cents/kWh. At

Continued on next page

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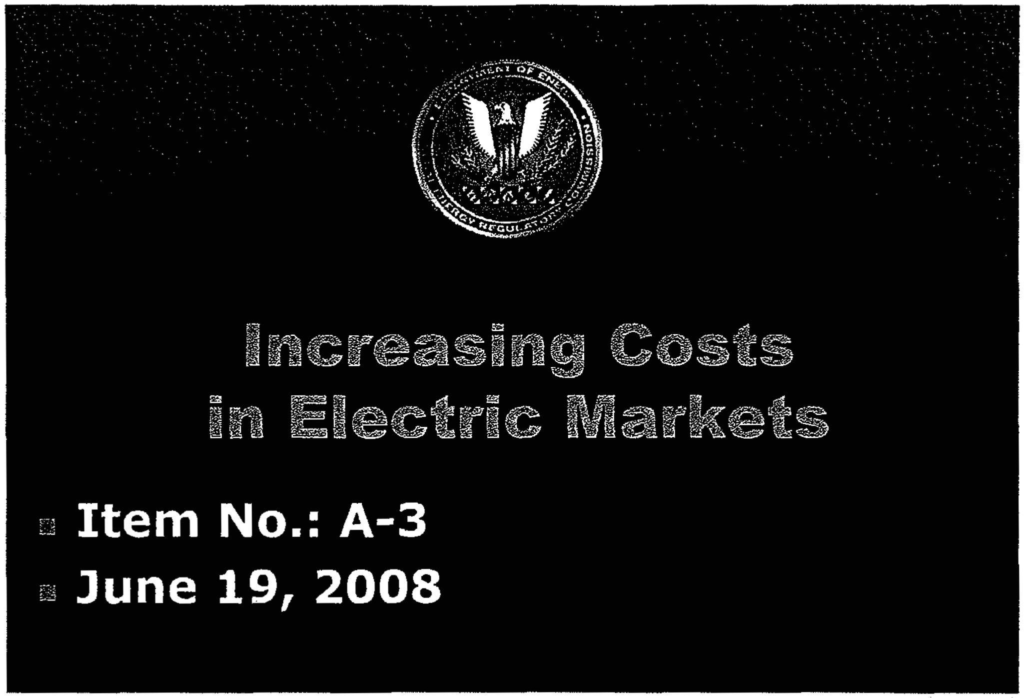
current prices, supplying that same kWh from a combined cycle gas plant would cost 9 cents just for the fuel. Adding to the likelihood of greater energy efficiency is that many states have adopted fairly strong energy efficiency standards.

Third, innovators see higher prices as an opportunity. By the nature of things, it's hard to predict what innovations will succeed. The electric industry has a number of technologies that might take off – including concentrating solar power, hydrokinetic power, and vehicle to grid technologies. In addition, distributed generation is becoming more important, and may continue to do so for both cost and emissions reasons In other newly competitive industries, such as telecoms and natural gas, innovations have produced large changes, sometimes quickly. Given continuing high electric prices, the electric power industry may see similar results.



That concludes our presentation. We welcome comments and questions.

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Rising Utility Construction Costs:

Sources and Impacts

Prepared by:

Marc W. Chupka
Gregory Basheda

The Brattle Group

Prepared for:

The EDISON FOUNDATION

SEPTEMBER 2007

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The Edison Foundation

The Edison Foundation is a nonprofit organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide.

Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people.

The Edison Foundation provides knowledge, insight, and leadership to achieve its goals through research, conferences, grants, and other outreach activities.

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Published by:
The Edison Foundation
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-347-5878

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Introduction and Executive Summary

In *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), *The Brattle Group* identified fuel and purchased-power cost increases as the primary driver of the electricity rate increases that consumers currently are facing. That report also noted that utilities are once again entering an infrastructure expansion phase, with significant investments in new baseload generating capacity, expansion of the bulk transmission system, distribution system enhancements, and new environmental controls. The report concluded that the industry could make the needed investments cost-effectively under a generally supportive rate environment.

The rate increase pressures arising from elevated fuel and purchased power prices continue. However, another major cost driver that was not explored in the previous work also will impact electric rates, namely, the substantial increases in the costs of building utility infrastructure projects. Some of the factors underlying these construction cost trends are straightforward—such as sharp increases in materials cost—while others are complex, and sometimes less transparent in their impact. Moreover, the recent rise in many utility construction cost components follows roughly a decade of relatively stable (or even declining) real construction costs, adding to the "sticker shock" that utilities experience when obtaining cost estimates or bids and that state public utility commissions experience during the process of reviewing applications for approvals to proceed with construction. While the full rate impact associated with construction cost increases will not be seen by customers until infrastructure projects are completed, the issue of rising construction costs currently affects industry investment plans and presents new challenges to regulators.

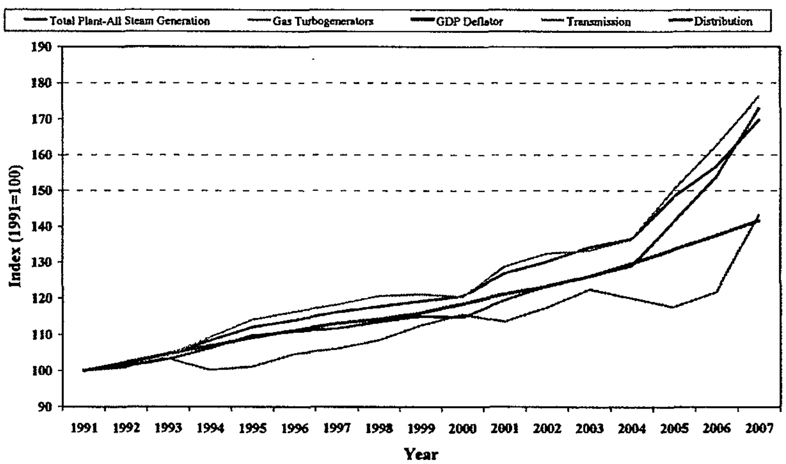
The purpose of this study is to a) document recent increases in the construction cost of utility infrastructure (generation, transmission, and distribution), b) identify the underlying causes of these increases, and c) explain how these increased costs will translate into higher rates that consumers might face as a result of required infrastructure investment. This report also provides a reference for utilities, regulators and the public to understand the issues related to recent construction cost increases. In summary, we find the following:

- Dramatically increased raw materials prices (*e.g.*, steel, cement) have increased construction cost directly and indirectly through the higher cost of manufactured components common in utility infrastructure projects. These cost increases have primarily been due to high global demand for commodities and manufactured goods, higher production and transportation costs (in part owing to high fuel prices), and a weakening U.S. dollar.
- Increased labor costs are a smaller contributor to increased utility construction costs, although that contribution may rise in the future as large construction projects across the country raise the demand for specialized and skilled labor over current or projected supply. There also is a growing backlog of

project contracts at large engineering, procurement and construction (EPC) firms, and construction management bids have begun to rise as a result. Although it is not possible to quantify the impact on future project bids by EPC firms, it is reasonable to assume that bids will become less cost-competitive as new construction projects are added to the queue.

- The price increases experienced over the past several years have affected all electric sector investment costs. In the generation sector, all technologies have experienced substantial cost increases in the past three years, from coal plants to windpower projects. Large proposed transmission projects have undergone cost revisions, and distribution system equipment costs have been rising rapidly. This is seen in Figure ES-1, which shows recent price trends in generation, transmission and distribution infrastructure costs based on the Handy-Whitman Index© data series, compared with the general price level as measured by the gross domestic product (GDP) deflator over the same time period.[1] As shown in Figure ES-1, infrastructure costs were relatively stable during the 1990s, but have experienced substantial price increases in the past several years. Between January 2004 and January 2007, the costs of steam-generation plant, transmission projects and distribution equipment rose by 25 percent to 35 percent (compared to an 8 percent increase in the GDP deflator). For example, the cost of gas turbines, which was fairly steady in the early part of the decade, increased by 17 percent during the year 2006 alone. As a result of these cost increases, the levelized capital cost component of baseload coal and nuclear plants has risen by $20/MWh or more—substantially narrowing coal's overall cost advantages over natural gas-fired combined-cycle plants—and thus limiting some of the cost-reduction benefits expected from expanding the solid-fuel fleet.

Figure ES-1
National Average Utility Infrastructure Cost Indices

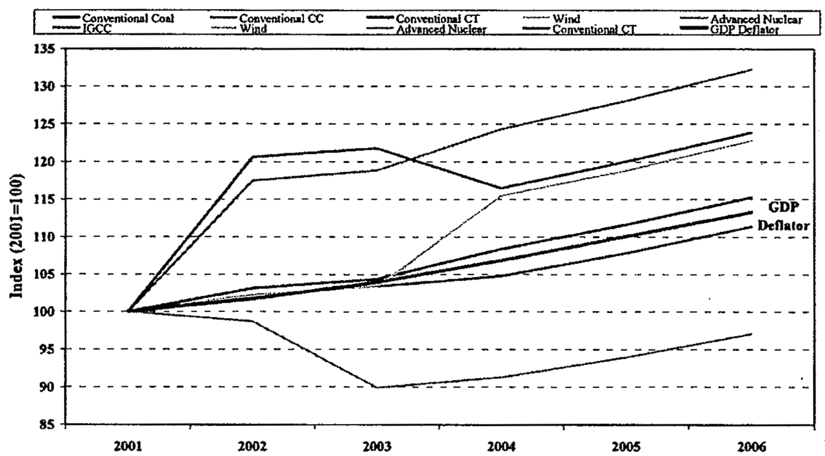


Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indexes for the specified components.

[1] The GDP deflator measures the cost of goods and services purchased by households, industry and government, and as such is a broader price index than the Consumer Price Index (CPI) or Producer Price Index (PPI), which track the costs of goods and services purchased by households and industry, respectively.

- The rapid increases experienced in utility construction costs have raised the price of recently completed infrastructure projects, but the impact has been mitigated somewhat to the extent that construction or materials acquisition preceded the most recent price increases. The impact of rising costs has a more dramatic impact on the estimated cost of proposed utility infrastructure projects, which fully incorporates recent price trends. This has raised significant concerns that the next wave of utility investments may be imperiled by the high cost environment. These rising construction costs have also motivated utilities and regulators to more actively pursue energy efficiency and demand response initiatives in order to reduce the future rate impacts on consumers.
- Despite the overwhelming evidence that construction costs have risen and will be elevated for some time, these increased costs are largely absent from the capital costs specified in the Energy Information Administration's (EIA's) 2007 *Annual Energy Outlook* (AEO). The AEO generation capital cost assumptions since 2001 are shown in Figure ES-2. Since 2004, capital costs of all technologies are assumed to grow at the general price level—a pattern that contradicts the market evidence presented in this report. The growing divergence between the AEO data assumptions and recent cost escalation is now so substantial that the AEO data need to be adjusted to reflect recent cost increases to provide reliable indicators of current or future capital costs.

Figure ES-2
EIA Generation Construction Cost Estimates



Sources: Data collected from the U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

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Projected Investment Needs and Recent Infrastructure Cost Increases

Current and Projected U.S. Investment in Electricity Infrastructure

The electric power industry is a very capital-intensive industry. The total value of generation, transmission and distribution infrastructure for regulated electric utilities is roughly $440 billion (property in service, net of accumulated depreciation and amortization), and capital expenditures are expected to exceed $70 billion in 2007.[2] Although the industry as a whole is always investing in capital, the rate of capital expenditures was relatively stable during the 1990s and began to rise near the turn of the century. As shown in *Why Are Electricity Prices Increasing? An Industry-Wide Perspective* (June 2006), utilities anticipate substantial increases in generation, transmission and distribution investment levels over the next two decades. Moreover, the significant need for new electricity infrastructure is a world-wide phenomenon: According to the *World Energy Investment Outlook 2006*, investments by power-sector companies throughout the world will total about $11 trillion dollars by 2030.[3]

Generation

As of December 31, 2005, there were 988 gigawatts (GW) of electric generating capacity in service in the U.S., with the majority of this capacity owned by electric utilities. Close to 400 GW of this total, or 39 percent, consists of natural gas-fired capacity, with coal-based capacity comprising 32 percent, or slightly more than 300 GW, of the U.S. electric generation fleet. Nuclear and hydroelectric plants comprise approximately 10 percent of the electric generation fleet. Approximately 49 percent of energy production is provided by coal plants, with 19 percent provided by nuclear plants. Natural gas-fired plants, which tend to operate as intermediate or peaking plants, also provided about 19 percent of U.S. energy production in 2006.

The need for installed generating capacity is highly correlated with load growth and projected growth in peak demand. According to EIA's most recent projections, U.S. electricity sales are expected to grow at an annual rate of about 1.4 percent through 2030. According to the North American Electric Reliability Corporation (NERC), U.S. non-coincident peak demand is expected to grow by 19 percent (141 GW) from 2006 to 2015. According to EIA, utilities will need to build 258 GW of new generating capacity by 2030 to meet the

[2] Net property in service figure as of December 31, 2006, derived from Federal Energy Regulatory Commission (FERC) Form 1 data compiled by the Edison Electric Institute (EEI). Gross property is roughly $730 billion, with about $290 billion already depreciated and/or amortized. Annual capital expenditure estimate is derived from a sample of 10K reports surveyed by EEI.

[3] Richard Stavros. "Power Plant Development: Raising the Stakes." *Public Utilities Fortnightly*, May 2007, pp. 36-42.

projected growth in electricity demand and to replace old, inefficient plants that will be retired. EIA further projects that coal-based capacity, that is more capital intensive than natural gas-fired capacity which dominated new capacity additions over the last 15 years, will account for about 54 percent of total capacity additions from 2006 to 2030. Natural gas-fired plants comprise 36 percent of the projected capacity additions in *AEO 2007*. EIA projects that the remaining 10 percent of capacity additions will be provided by renewable generators (6 percent) and nuclear power plants (4 percent). Renewable generators and nuclear power plants, similar to coal-based plants, are capital-intensive technologies with relatively high construction costs but low operating costs.

High-Voltage Transmission

The U.S. and Canadian electric transmission grid includes more than 200,000 miles of high voltage (230 kV and higher) transmission lines that ultimately serve more than 300 million customers. This system was built over the past 100 years, primarily by vertically integrated utilities that generated and transmitted electricity locally for the benefit of their native load customers. Today, 134 control areas or balancing authorities manage electricity operations for local areas and coordinate reliability through the eight regional reliability councils of NERC.

After a long period of decline, transmission investment began a significant upward trend starting in the year 2000. Since the beginning of 2000, the industry has invested more than $37.8 billion in the nation's transmission system. In 2006 alone, investor-owned electric utilities and stand-alone transmission companies invested an historic $6.9 billion in the nation's grid, while the Edison Electric Institute (EEI) estimates that utility transmission investments will increase to $8.0 billion during 2007. A recent EEI survey shows that its members plan to invest $31.5 billion in the transmission system from 2006 to 2009, a nearly 60-percent increase over the amount invested from 2002 to 2005. These increased investments in transmission are prompted in part by the larger scale of base load generation additions that will occur farther from load centers, creating a need for larger and more costly transmission projects than those built over the past 20 years. In addition, new government policies and industry structures will contribute to greater transmission investment. In many parts of the country, transmission planning has been formally regionalized, and power markets create greater price transparency that highlights the value of transmission expansion in some instances.

NERC projects that 12,873 miles of new transmission will be added by 2015, an increase of 6.1 percent in the total miles of installed extra high-voltage (EHV) transmission lines (230 kV and above) in North America over the 2006 to 2015 period. NERC notes that this expansion lags demand growth and expansion of generating resources in most areas. However, NERC's figures do not include several major new transmission projects proposed in the PJM Interconnection LLC, such as the major new lines proposed by American Electric Power, Allegheny Power, and Pepco.

Distribution

While transmission systems move bulk power across wide areas, distribution systems deliver lower-voltage power to retail customers. The distribution system includes poles, as well as metering, billing, and other related infrastructure and software associated with retail sales and customer care functions. Continual investment in distribution facilities is needed, first and foremost, to keep pace with growth in customer demand. In real terms, investment began to increase in the mid-1990s, preceding the corresponding boom in generation. This steady climb in investment in distribution assets shows no sign of diminishing. The need to replace an aging infrastructure, coupled with increased population growth and demand for power quality and customer service, is continuing to motivate utilities to improve their ultimate delivery system to customers.

Continued customer load growth will require continued expansion in distribution system capacity. In 2006, utilities invested about $17.3 billion in upgrading and expanding distribution systems, a 32-percent increase over the investment levels incurred in 2004. EEI projects that distribution investment during 2007 will again exceed $17.0 billion. While much of the recent increase in distribution investment reflects expanding physical infrastructure, a substantial portion of the increased dollar investment reflects the increased input costs of materials and labor to meet current distribution infrastructure needs.

Construction Costs for Recently Completed Generation

The majority of recently constructed plants have been either natural gas-fired or wind power plants. Both have displayed increasing real costs for several years. Since the 1990s, most of the new generating capacity built in the U.S. has been natural gas-fired capacity, either natural gas-fired combined-cycle units or natural gas-fired combustion turbines. Combustion turbine prices recently rose sharply after years of real price decreases, while significant increases in the cost of installed natural gas combined-cycle combustion capacity have emerged during the past several years.

Using commercially available databases and other sources, such as financial reports, press releases and government documents, *The Brattle Group* collected data on the installation cost of natural gas-fired combined-cycle generating plants built in the U.S. during the last major construction cycle, defined as generating plants brought into service between 2000 and 2006. We estimated that the average real construction cost of all natural gas-fired combined-cycle units brought online between 2000 and 2006 was approximately $550/kilowatt (kW) (in 2006 dollars), with a range of costs between $400/kW to approximately $1,000/kW. Statistical analysis confirmed that real installation cost was influenced by plant size, the turbine technology, the NERC region in which the plant was located, and the commercial online date. Notably, we found a positive and statistically significant relationship between a plant's construction cost and its online date, meaning that, everything else equal, the later a plant was brought online, the higher its real installation cost.[4] Figure 1 shows the average yearly installation cost, in *nominal* dollars, as predicted by the regression analysis.[5] This figure shows that the average installation cost of combined-cycle units increased gradually from 2000 to 2003, followed by a fairly significant increase in 2004 and a very significant escalation—more than $300/kW—in 2006. This provides vivid evidence of the recent sharp increase in plant construction costs.

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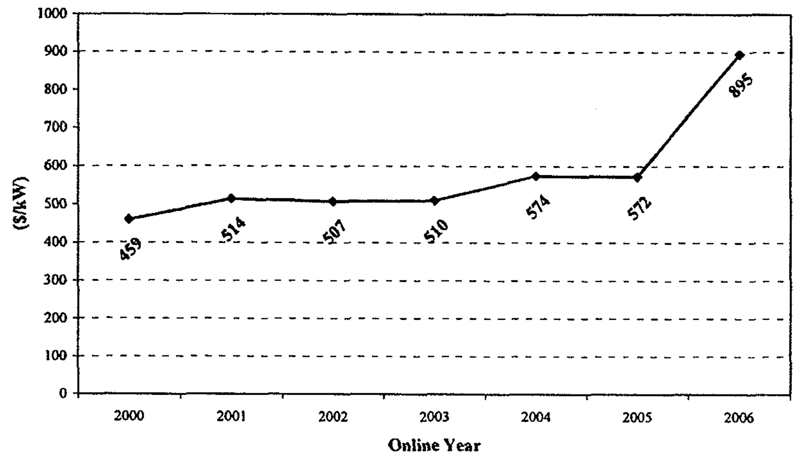
[4] To be precise, we used a "dummy" variable to represent each year in the analysis. The year-specific dummy variables were statistically significant and uniformly positive; *i.e.*, they had an upward impact on installation cost.

[5] The nominal form regression results are discussed here to facilitate comparison with the GDP deflator measure used to compare other price trends in other figures in this report.

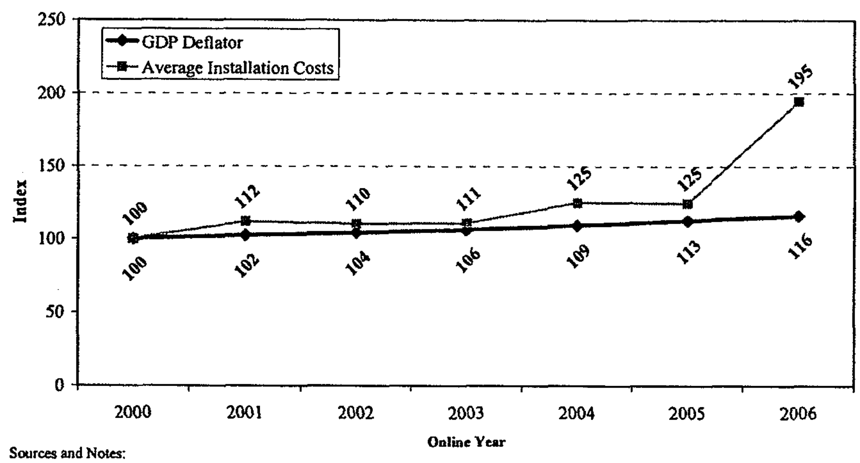
Figure 1
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year ($/kW)



Sources and Notes:
* Data on summer capacity, total installation cost, turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.

Figure 2 compares the trend in plant installation costs to the GDP deflator, using 2000 as the base year. Over the period of 2000 to 2006, the cumulative increase in the general price level was 16 percent while the cumulative increase in the installation cost of new combined-cycle units was almost 95 percent, with much of this increase occurring in 2006.

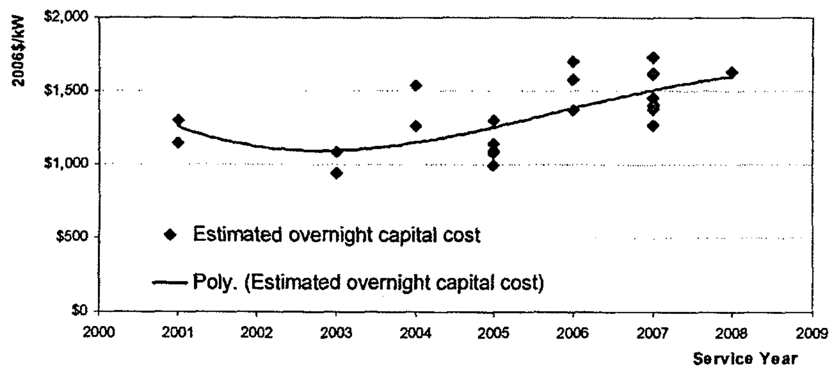
Figure 2
Multi-Variable Regression Estimation:
Average Nominal Installation Costs Based on Online Year (Index Year 2000 = 100)



Sources and Notes:
* Data on summer capacity, total installation cost, turbine technology, commercial online date, and zip code for the period 2000-2006 were collected from commercially available databases and other sources such as company websites and 10k reports.
** GDP Deflator data were collected from the U.S. Bureau of Economic Analysis.

Another major class of generation development during this decade has been wind generation, the costs of which have also increased in recent years. The Northwest Power and Conservation Council (NPCC), a regional planning council that prepares long-term electric resource plans for the Pacific Northwest, issued its most recent review of the cost of wind power in July 2006.[6] The Council found that the cost of new wind projects rose substantially in real terms in the last two years, and was much higher than that assumed in its most recent resource plan. Specifically, the Council found that the levelized lifecycle cost of power for new wind projects rose 50 to 70 percent, with higher construction costs being the principal contributor to this increased cost. According to the Council, the construction cost of wind projects, in real dollars, has increased from about $1150/kW to $1300-$1700/kW in the past few years, with an unweighted average capital cost of wind projects in 2006 at $1,485/kW. Factors contributing to the increase in wind power costs include a weakening dollar, escalation of commodity and energy costs, and increased demand for wind power under renewable portfolio standards established by a growing number of states. The Council notes that commodities used in the manufacture and installation of wind turbines and ancillary equipment, including cement, copper, steel and resin have experienced significant cost increases in recent years. Figure 3 shows real construction costs of wind projects by actual or projected in-service date.

Figure 3
Wind Power Project Capital Costs



Source: The Northwest Power and Conservation Council, "Biennial Review of the Cost of Windpower" July 13, 2006.

These observations were confirmed recently in a May 2007 report by the U.S. Department of Energy (DOE), which found that prices for wind turbines (the primary cost component of installed wind capacity) rose by more than $400/kW between 2002 and 2006, a nearly 60-percent increase.[7] Figure 4 is reproduced from the DOE report (Figure 21) and shows the significant upward trend in turbine prices since 2001.

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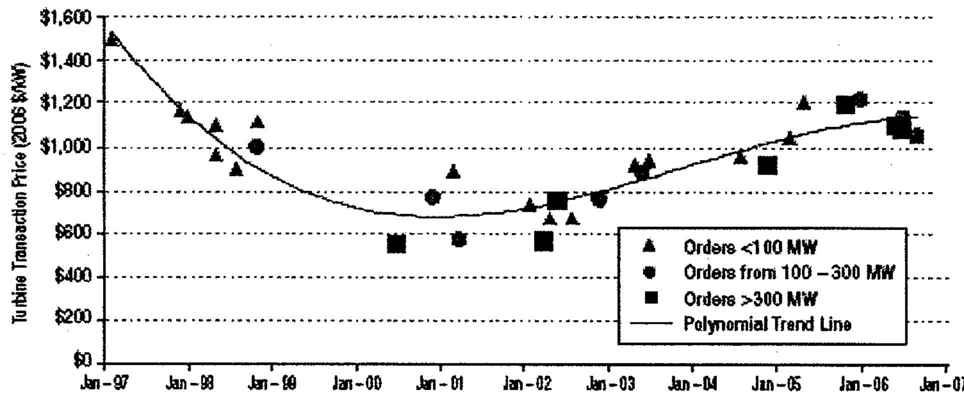
[6] The NPCC planning studies and analyses cover the following four states: Washington, Oregon, Idaho, and Montana. See "Biennial Review of the Cost of Windpower" July 13, 2006, at www.bpa.gov/Energy/N/projects/post2006conservation/doc/Windpower_Cost_Review.doc. This study provides many reasons for windpower cost increases.

[7] See U.S. Department of Energy, *Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2006* Figure 21, page 16.

Figure 4
Wind Turbine Prices 1997 - 2007



Source: Berkeley Lab database.

Rising Projected Construction Costs: Examples and Case Studies

Although recently completed gas-fired and wind-powered capacity has shown steady real cost increases in recent years, the most dramatic cost escalation figures arise from *proposed* utility investments, which fully reflect the recent, sharply rising prices of various components of construction and installation costs. The most visible of these are generation proposals, although several transmission proposals also have undergone substantial upward cost revisions. Distribution-level investments are smaller and less discrete ("lumpy") and thus are not subject to similar ongoing public scrutiny on a project-by-project basis.

Coal-Based Power Plants

Evidence of the significant increase in the construction cost of coal-based power plants can be found in recent applications filed by utilities, such as Duke Energy and Otter Tail Power Company, seeking regulatory approval to build such plants. Otter Tail Power Company leads a consortium of seven Midwestern utilities that are seeking to build a 630-MW coal-based generating unit (Big Stone II) on the site of the existing Big Stone Plant near Milbank, South Dakota. In addition, the developers of Big Stone II seek to build a new high-voltage transmission line to deliver power from Big Stone II and from other sources, including possibly wind and other renewable forms of energy. Initial cost estimates for the power plant were about $1 billion, with an additional $200 million for the transmission line project. However, these cost estimates increased dramatically, largely due to higher costs for construction materials and labor.[8] Based on the most recent design refinements, the project, including transmission, is expected to cost $1.6 billion.

[8] Other factors contributing to the cost increase include design changes made by project participants to increase output and improve the unit's efficiency. For example, the voltage of the proposed transmission line was increased from 230 kV to 345 kV to accommodate more generation.

In June 2006, Duke submitted a filing with the North Carolina Utilities Commission (NCUC) seeking a certificate of public convenience and necessity for the construction of two 800 MW coal-based generating units at the site of the existing Cliffside Steam Station. In its initial application, Duke relied on a May 2005 preliminary cost estimate showing that the two units would cost approximately $2 billion to build. Five months later, Duke submitted a second filing with a significantly revised cost estimate. In its second filing, Duke estimated that the two units would cost approximately $3 billion to build, a 50 percent cost increase. The North Carolina Utilities Commission approved the construction of one 800 MW unit at Cliffside but disapproved the other unit, primarily on the basis that Duke had not made a showing that it needed the capacity to serve projected native load demands. Duke's latest projected cost for building one 800 MW unit at Cliffside is approximately $1.8 billion, or about $2,250/kW. When financing costs, or allowance for funds used during construction (AFUDC), are included, the total cost is estimated to be $2.4 billion (or about $3,000/kW).

Rising construction costs have also led utilities to reconsider expansion plans prior to regulatory actions. In December 2006, Westar Energy announced that it was deferring the consideration of a new 600 MW coal-based generation facility due to significant increases in the estimated construction costs, which increased from $1.0 billion to about $1.4 billion since the plant was first announced in May 2005.

Increased construction costs are also affecting proposed demonstration projects. For example, DOE announced earlier this year that the projected cost for one of its most prominent clean coal demonstration project, FutureGen, had nearly doubled.[9] FutureGen is a clean coal demonstration project being pursued by a public-private partnership involving DOE and an alliance of industrial coal producers and electric utilities. FutureGen is an experimental advanced Integrated Gasification Combined Cycle (IGCC) coal plant project that will aim for near zero emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury, particulates and carbon dioxide (CO_2). Its initial cost was estimated at $950 million. But after re-evaluating the price of construction materials and labor and adjusting for inflation over time, DOE's Office of Fossil Energy announced that the project's price had increased to $1.7 billion.

<u>Transmission Projects</u>

NSTAR, the electric distribution company that serves the Boston metropolitan area, recently built two 345 kV lines from a switching station in Stoughton, Massachusetts, to substations in the Hyde Park section of Boston and to South Boston, respectively. In an August 2004 filing before ISO New England Inc. (ISO-NE), NSTAR indicated that the project would cost $234.2 million. In March 2007, NSTAR informed ISO-NE that estimated project costs had increased by $57.7 million, or almost 25 percent, for a revised total project cost of $292 million. NSTAR stated that the increase is driven by increases in both construction and material costs, with construction bids coming in 24 percent higher than initially estimated. NSTAR further explained that there have been dramatic increases in material costs, with copper costs increasing by 160 percent, core steel by 70 percent, flow-fill concrete by 45 percent, and dielectric fluid (used for cable cooling) by 66 percent.

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[9] U.S. Department of Energy, April 10, 2007, press release available at http://www.fossil.energy.gov/news/techlines/2007/07019-DOE_Signs_FutureGen_Agreement.html

Another aspect of transmission projects is land requirements, and in many areas of the country land prices have increased substantially in the past few years. In March 2007, the California Public Utilities Commission (CPUC) approved construction of the Southern California Edison (SCE) Company's proposed 25.6-mile, 500 kV transmission line between SCE's existing Antelope and Pardee Substations. SCE initially estimated a cost of $80.3 million for the Antelope-Pardee 500 kV line. However, the company subsequently revised its estimate by updating the anticipated cost of acquiring a right-of-way, reflecting a rise in California's real estate prices. The increased land acquisition costs increased the total estimate for the project to $92.5 million, increasing the estimated costs to more than $3.5 million per mile.

Distribution Equipment

Although most individual distribution projects are small relative to the more visible and public generation and transmission projects, costs have been rising in this sector as well. This is most readily seen in Handy-Whitman Index© price series relating to distribution equipment and components. Several important categories of distribution equipment have experienced sharp price increases over the past three years. For example, the prices of line transformers and pad transformers have increased by 68 percent and 79 percent, respectively, between January 2004 and January 2007, with increases during 2006 alone of 28 percent and 23 percent.[10] The cost of overhead conductors and devices increased over the past three years by 34 percent, and the cost of station equipment rose by 38 percent. These are in contrast to the overall price increases (measured by the GDP deflator) of roughly 8 percent over the past three years.

[10] Handy-Whitman© Bulletin No. 165, average increase of six U.S. regions. Used with permission.

Factors Spurring Rising Construction Costs

Broadly speaking, there are four primary sources of the increase in construction costs: (1) material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs (*e.g.*, transformers, turbines, pumps); (2) shop and fabrication capacity for manufactured components (relative to current demand); (3) the cost of construction field labor, both unskilled and craft labor; and (4) the market for large construction project management, *i.e.*, the queuing and bidding for projects. This section will discuss each of these factors.

Material Input Costs

Utility construction projects involve large quantities of steel, aluminum and copper (and components manufactured from these metals) as well as cement for foundations, footings and structures. All of these commodities have experienced substantial recent price increases, due to increased domestic and global demands as well as increased energy costs in mineral extraction, processing and transportation. In addition, since many of these materials are traded globally, the recent performance of the U.S. dollar will impact the domestic costs (see box on page 14).

Metals

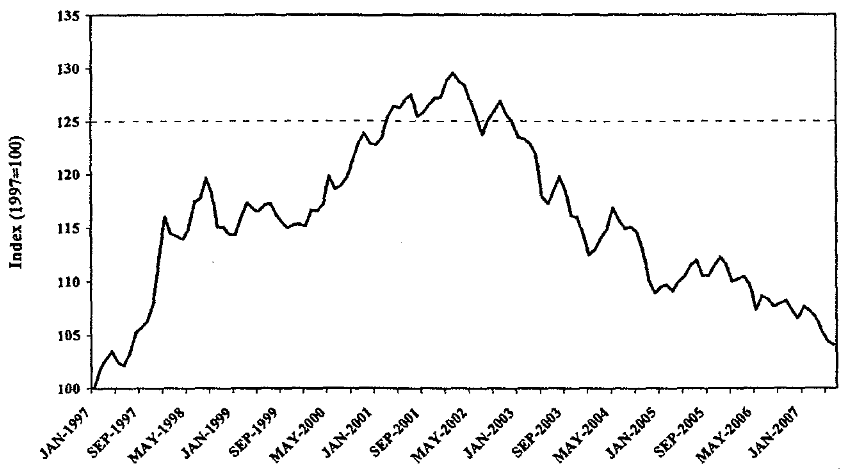
After being relatively stable for many years (and even declining in real terms), the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years. These increases are primarily the result of high global demand and increased production costs (including the impact of high energy prices). A weakening U.S. dollar has also contributed to high domestic prices for imported metals and various component products.

Figure 5 shows price indices for primary inputs into steel production (iron and steel scrap, and iron ore) since 1997. The price of both inputs fell in real terms during the late 1990s, but rose sharply after 2002. Compared to the 20-percent increase in the general inflation rate (GDP deflator) between 1997 and 2006, iron ore prices rose 75 percent and iron and steel scrap prices rose nearly 120 percent. The increase over the last few years was especially sharp—between 2003 and 2006, prices for iron ore rose 60 percent and iron and scrap steel rose 150 percent.

Exchange Rates

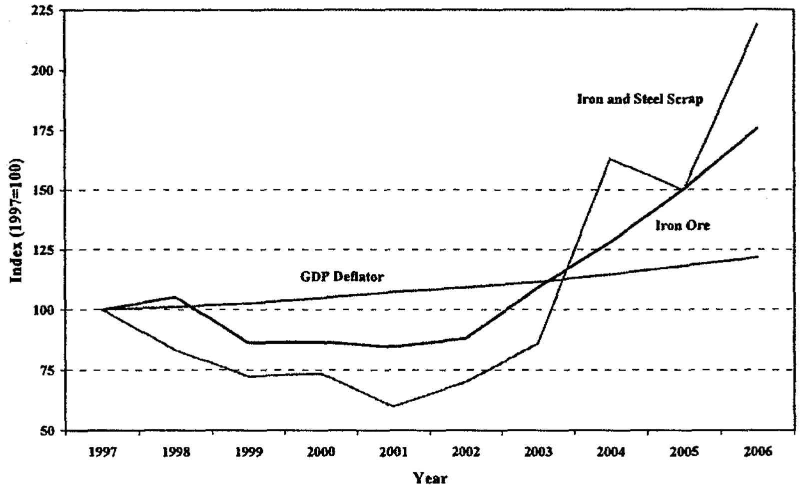
Many of the raw materials involved in utility construction projects (e.g., steel, copper, cement), as well as many major manufactured components of utility infrastructure investments, are globally traded. This means that prices in the U.S. are also affected by exchange rate fluctuations, which have been adverse to the dollar in recent years. The chart below shows trade-weighted exchange rates from 1997. Although the dollar appreciated against other currencies between 1997 and 2001, the graph also clearly shows a substantial erosion of the dollar since the beginning of 2002, losing roughly 20 percent of its value against other major trading partners' currencies. This has had a substantial impact on U.S. material and manufactured component prices, as will be reflected in many of the graphs that follow.

Nominal Broad Dollar Index



Source: U.S. Federal Reserve Board, Statistical Release, Broad Index Foreign Exchange Value of the Dollar.

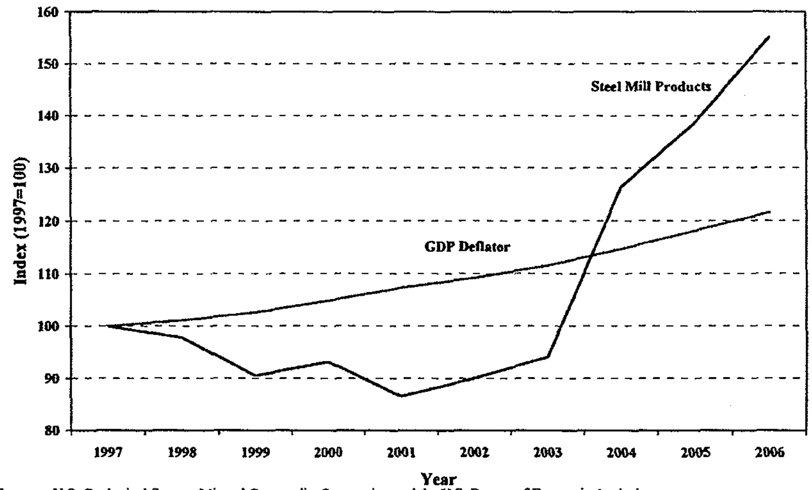
Figure 5
Inputs to Iron and Steel Production Cost Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

The increase in input prices has been reflected in steel mill product prices. Figure 6 compares the trend in steel mill product prices to the general inflation rate (using the GDP deflator) over the past 10 years. Figure 6 shows that the price of steel has increased about 60 percent since 2003.

Figure 6
Steel Mill Products Price Index



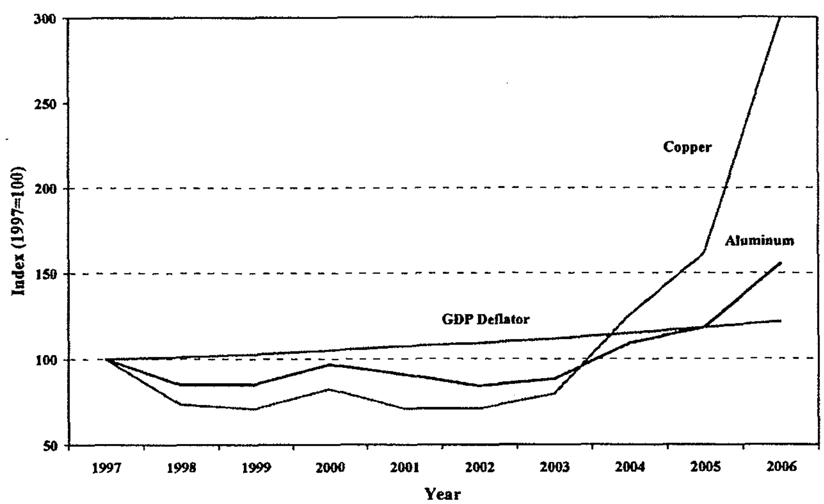
Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Various sources point to the rapid growth of steel production and demand in China as a primary cause of the increases in both steel prices and the prices of steelmaking inputs.[11] China has become both the world's largest steelmaker and steel consumer. In addition, some analysts contend that steel companies have achieved greater pricing power, partly due to ongoing consolidation of the industry, and note that recently increased demand for steel has been driven largely by products used in energy and heavy industry, such as plate and structural steels.

From the perspective of the steel industry, the substantial and at least semi-permanent rise in the price of steel has been justified by the rapid rise in the price of many steelmaking inputs, such as steel scrap, iron ore, coking coal, and natural gas. Today's steel prices remain at historically elevated levels and, based on the underlying causes for high prices described, it appears that iron and steel costs are likely to remain at these high levels at least for the near future.

Other metals important for utility infrastructure display similar price patterns: declining real prices over the first five years or so of the previous 10 years, followed by sharp increases in the last few years. Figure 7 shows that aluminum prices doubled between 2003 and 2006, while copper prices nearly quadrupled over the same period.

Figure 7
Aluminum and Copper Price Indices

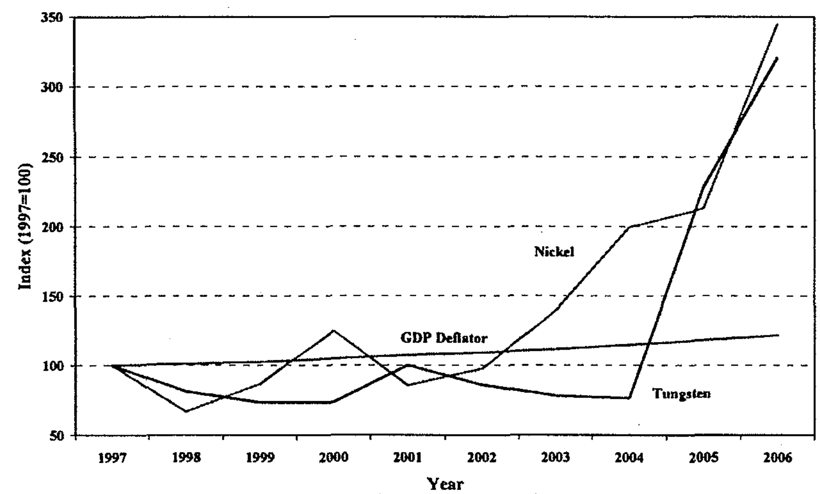


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

[11] See, for example, *Steel: Price and Policy Issues*, CRS Report to Congress, Congressional Research Service, August 31, 2006.

These price increases were also evident in metals that contribute to important steel alloys used broadly in electrical infrastructure, such as nickel and tungsten. The prices of these display similar patterns, as shown in Figure 8.

Figure 8
Nickel and Tungsten Price Indices

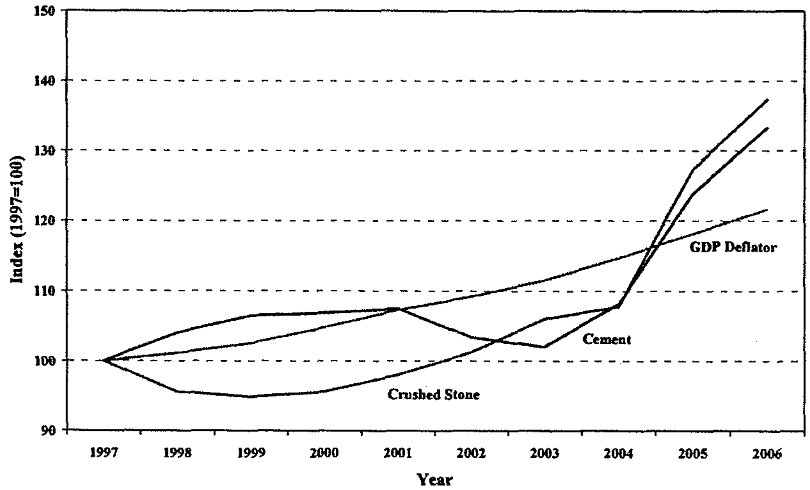


Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

Cement, Concrete, Stone and Gravel

Large infrastructure projects require huge amounts of cement as well as basic stone materials. The price of cement has also risen substantially in the past few years, for the same reasons cited above for metals. Cement is an energy-intensive commodity that is traded on international markets, and recent price patterns resemble those displayed for metals. In utility construction, cement is often combined with stone and other aggregates for concrete (often reinforced with steel), and there are other site uses for sand, gravel and stone. These materials have also undergone significant price increases, primarily as a result of increased energy costs in extraction and transportation. Figure 9 shows recent price increases for cement and crushed stone. Prices for these materials have increased about 30 percent between 2004 and 2006.

Figure 9
Cement and Crushed Stone Price Indices



Sources: U.S. Geological Survey, Mineral Commodity Summaries, and the U.S. Bureau of Economic Analysis.

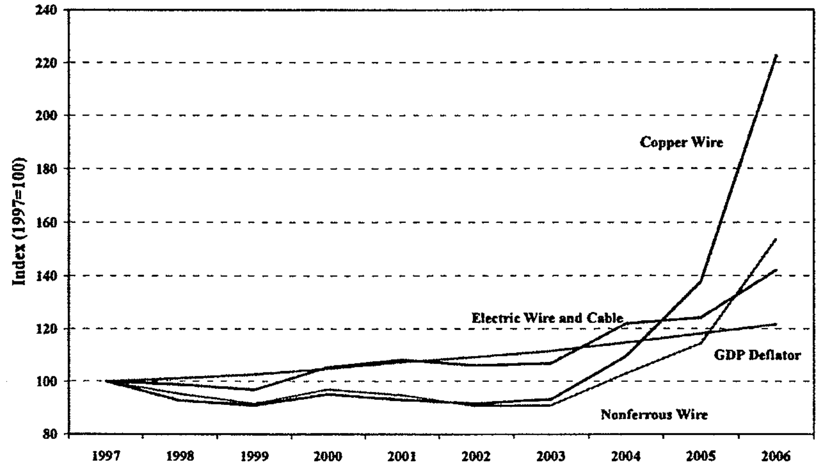
Manufactured Products for Utility Infrastructure

Although large utility construction projects consume substantial amounts of unassembled or semi-finished metal products (*e.g.*, reinforcing bars for concrete, structural steel), many of the components such as conductors, transformers and other equipment are manufactured elsewhere and shipped to the construction site. Available price indices for these components display similar patterns of recent sharp price increases.

Figure 10 shows the increased prices experienced in wire products compared to the inflation rate, according to the U.S. Bureau of Labor Statistics (BLS), highlighting the impact of underlying metal price increases.

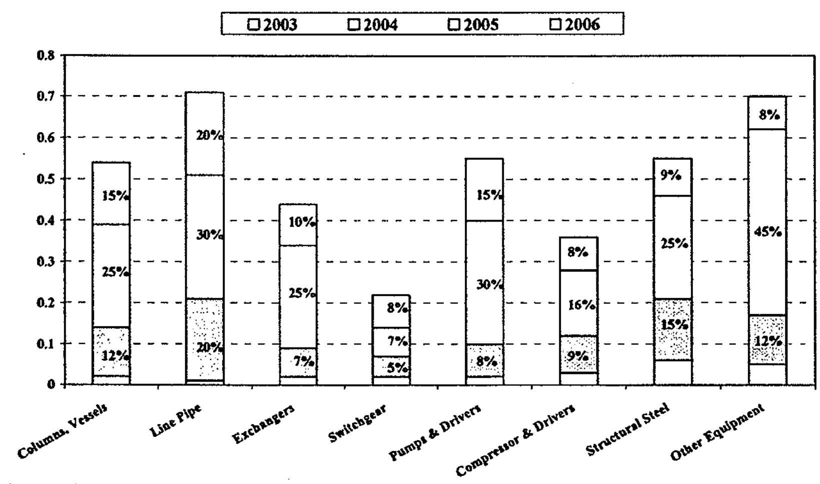
Manufactured components of generating facilities—large pressure vessels, condensers, pumps, valves—have also increased sharply since 2004. Figure 11 shows the yearly increases experienced in key component prices since 2003.

Figure 10
Electric Wire and Cable Price Indices



Sources: The U.S. Bureau of Labor Statistics and the U.S. Bureau of Economic Analysis.

Figure 11
Equipment Price Increases

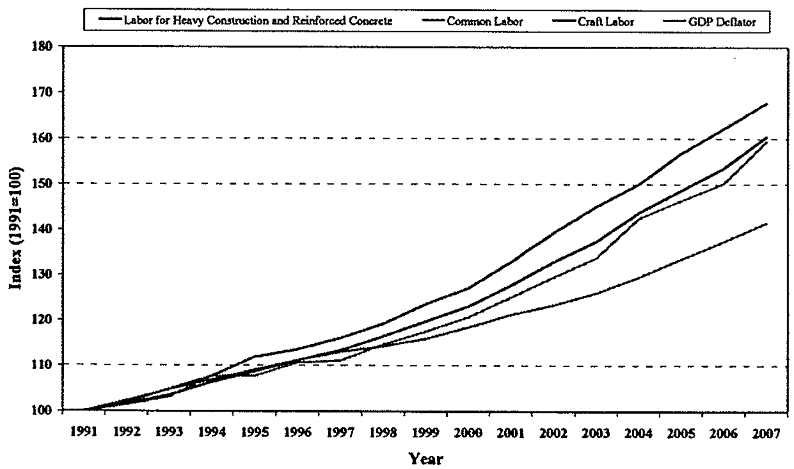


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Labor Costs

A significant component of utility construction costs is labor—both unskilled (common) labor as well as craft labor such as pipefitters and electricians. Labor costs have also increased at rates higher than the general inflation rate, although more steadily since 1997, and recent increases have been less dramatic than for commodities. Figure 12 shows a composite national labor cost index based on simple averages of the regional Handy-Whitman Index© for common and craft labor. Between January 2001 and January 2007, the general inflation rate (measured by the GDP deflator) increased about 15 percent. During the same period, the cost of craft labor and heavy construction labor increased about 26 percent, while common labor increased 27 percent, or almost twice the rate of general inflation.[12] While less severe than commodity cost increases, increased labor costs contributed to the overall construction cost increases because of their substantial share in overall utility infrastructure construction costs.

Figure 12
National Average Labor Costs Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional labor cost indices for the specified types of labor.

Although labor costs have not risen dramatically in recent years, there is growing concern about an emerging gap between demand and supply of skilled construction labor—especially if the anticipated boom in utility construction materializes. In 2002, the Construction Users Roundtable (CURT), surveyed its members and found that recruitment, education, and retention of craft workers continue to be critical issues for the industry.[13] The average age of the current construction skilled workforce is rising rapidly, and high attrition rates in construction are compounding the problem. The industry has always had high attrition at the entry-level positions, but now many workers in the 35-40 year-old age group are leaving the industry for a variety of reasons. The latest projections indicate that, because of attrition and anticipated growth, the construction

[12] These figures represent a simple average of six regional indices, however, local and regional labor markets can vary substantially from these national averages.

[13] *Confronting the Skilled Construction Workforce Shortage*. The Construction Users Roundtable, WP-401, June 2004, p. 1.

industry must recruit 200,000 to 250,000 new craft workers per year to meet future needs. However, both demographics and a poor industry image are working against the construction industry as it tries to address this need.[14]

There also could be a growing gap between the demand and supply of electrical lineworkers who maintain the electric grid and who perform much of the labor for transmission and distribution investments. These workers erect poles and transmission towers and install or repair cables or wires used to carry electricity from power plants to customers. According to a DOE report, demand for such workers is expected to outpace supply over the next decade.[15] The DOE analysis indicates a significant forecasted shortage in the availability of qualified candidates by as many as 10,000 lineworkers, or nearly 20 percent of the current workforce. As of 2005, lineworkers earned a mean hourly wage of $25/hour, or $52,300 per year. The forecast supply shortage will place upward pressure on the wages earned by lineworkers.[16]

Shop and Fabrication Capacity

Many of the components of utility projects—including large components like turbines, condensers, and transformers—are manufactured, often as special orders to coincide with particular construction projects. Because many of these components are not held in large inventories, the overall capacity of their manufacturers can influence the prices obtained and the length of time between order and delivery. The price increases of major manufactured components were shown in Figure 11. While equipment and component prices obviously reflect underlying material costs, some of the price increases of manufactured components and the delivery lags are due to manufacturing capacity constraints that are not readily overcome in the near term.

As shown in Figure 13 and Figure 14, recent orders have largely eliminated spare shop capacity, and delivery times for major manufactured components have risen. These constraints are adding to price increases and are difficult to overcome with imported components because of the lower value of the dollar in recent years.

The increased delivery times can affect utility construction costs through completion delays that increase the cost of financing a project. In general, utilities commit substantial funds during the construction phase of a project that have to be financed either through debt or equity, called "allowance for fund used during construction" (AFUDC). All else held equal, the longer the time from the initiation through completion of a project, the higher is the financing costs of the investment and the ultimate costs passed through to ratepayers.

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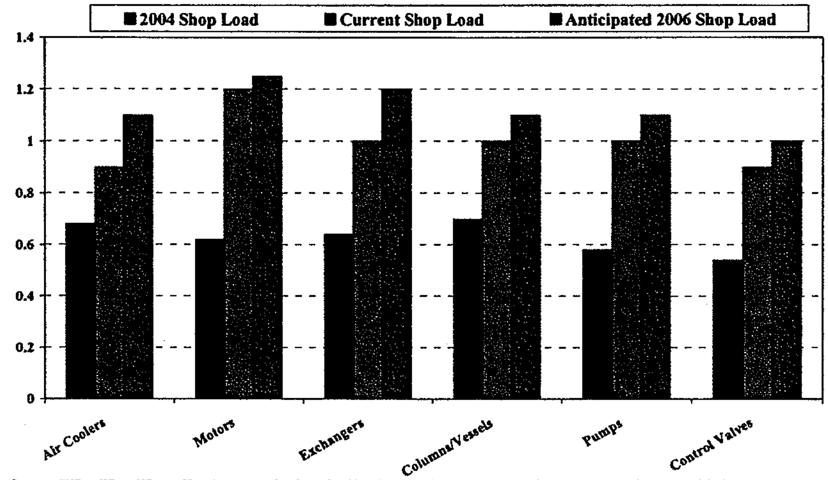
[14] *Id.*, p. 1.

[15] *Workforce Trends in the Electric Utility Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005.* U.S. Department of Energy, August 2006, p. xi.

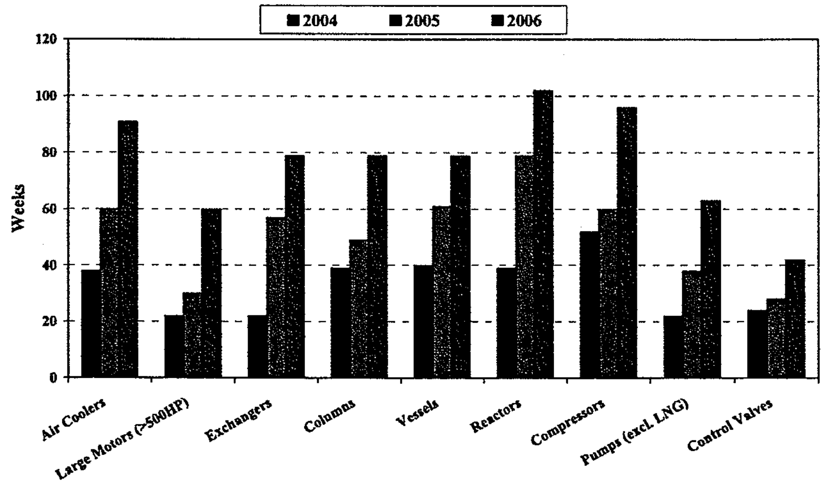
[16] *Id.*, p. 5.

Figure 13
Shop Capacity



Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Figure 14
Delivery Schedules

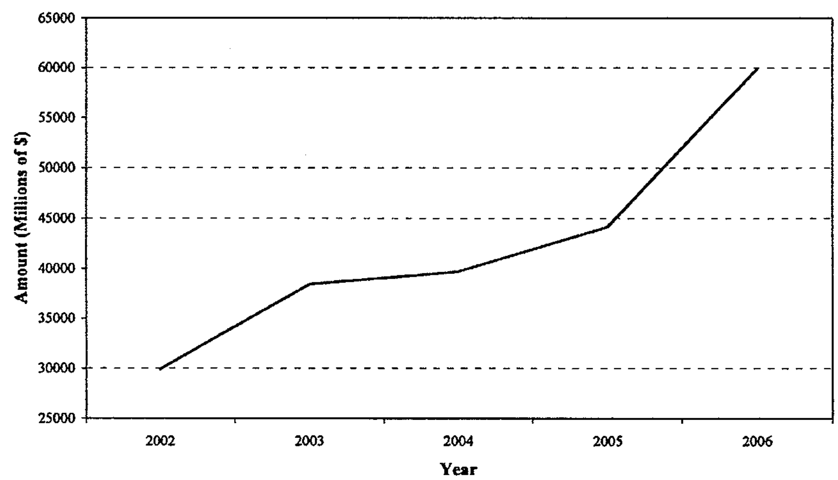


Source: "Who, What, Where, How" presentation by John Siegel, Bechtel Power Corp. Delivered at the conference entitled *Next Generation of Generation* (Dewey Ballantine LLP), May 4, 2006.

Engineering, Procurement and Construction (EPC) Market Conditions

Increased worldwide demand for new generating and other electric infrastructure projects, particularly in China, has been cited as a significant reason for the recent escalation in the construction cost of new power plants. This suggests that major Engineering, Procurement and Construction (EPC) firms should have a growing backlog of utility infrastructure projects in the pipeline. While we were unable to obtain specific information from the major EPC firms on their worldwide backlog of electric utility infrastructure projects (*i.e.*, the number of electric utility projects compared with other infrastructure projects such as roads, port facilities and water infrastructure, in their respective pipelines), we examined their financial statements, which specify the financial value associated with their backlog of infrastructure projects. Figure 15 shows the cumulative annual financial value associated with the backlog of infrastructure projects at the following four major EPC firms; Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. Figure 15 shows that the annual backlog of infrastructure projects rose sharply between 2005 and 2006, from \$4.1 billion to \$5.6 billion, an increase of 37 percent. This significant increase in the annual backlog of infrastructure projects at EPC firms is consistent with the data showing an increased worldwide demand for infrastructure projects in general and also utility generation, transmission, and distribution projects.

Figure 15
Annual Backlog at Major EPC Firms



Data are compiled from the Annual Reports of Fluor Corporation, Bechtel Corporation, The Shaw Group Inc., and Tyco International Ltd. For Bechtel, the data represent new booked work, as backlog is not reported.

The growth in construction project backlogs likely will dampen the competitiveness of EPC bids for future projects, at least until the EPC industry is able to expand capacity to manage and execute greater volumes of projects. This observation does not imply that this market is generally uncompetitive—rather it reflects the limited ability of EPC firms with near-term capacity constraints to service an upswing in new project development associated with a boom period in infrastructure construction cycles. Such constraints, combined with a rapidly filling (or full) queue for project management services, limit incentives to bid aggressively on new projects.

Although difficult to quantify, this lack of spare capacity in the EPC market will undoubtedly have an upward price pressure on new bids for EPC services and contracts. A recent filing by Oklahoma Gas & Electric Company (OG&E) seeking approval of the Red Rock plant (a 950 MW coal unit) provides a demonstration of this effect. In January 2007, OG&E testimony indicated that their February 3, 2006, cost estimate of nearly $1,700/kW had been revised to more than $1,900/kW by September 29, 2006, a 12-percent increase in just nine months. More than half of the increase (6.6 percent) was ascribed to change in market conditions which "reflect higher materials costs (steel and concrete), escalation in major equipment costs, and a significant tightening of the market for EPC contractor services (as there are relatively few qualified firms that serve the power plant development market)."[17] In the detailed cost table, OG&E indicated that the estimate for EPC services had increased by more than 50 percent during the nine month period (from $223/kW to $340/kW).

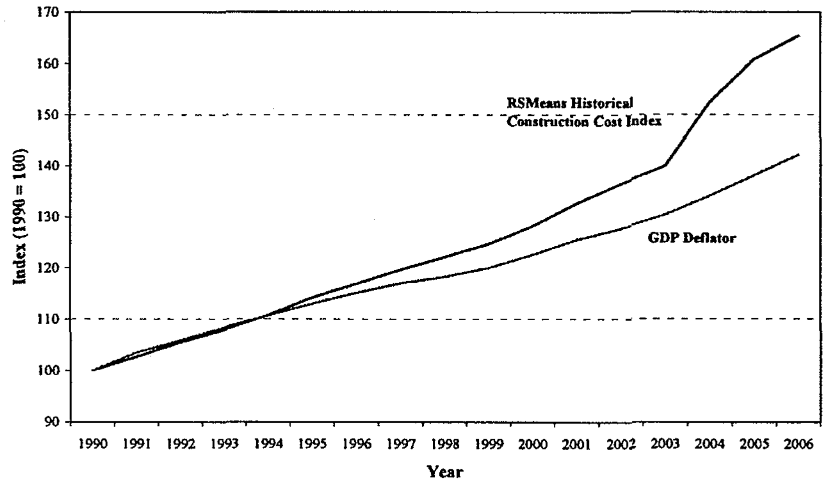
Summary Construction Cost Indices

Several sources publish summary construction cost indices that reflect composite costs for various construction projects. Although changes in these indices depend on the actual cost weights assumed *e.g.*, labor, materials, manufactured components, they provide useful summary measures for large infrastructure project construction costs.

The RSMeans Construction Cost Index provides a general construction cost index, which reflects primarily building construction (as opposed to utility projects). This index also reflects many of the same cost drivers as large utility construction projects such as steel, cement and labor. Figure 16 shows the changes in the RSMeans Construction Cost index since 1990 relative to the general inflation rate. While the index rose slightly higher than the GDP deflator beginning in the mid 1990s, it shows a pronounced increase between 2003 and 2006 when it rose by 18 percent compared to the 9 percent increase in general inflation.

[17] Testimony of Jesse B. Langston before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200700012, January 17, 2007, page 27 and Exhibit JBL-9.

Figure 16
RSMeans Historical Construction Cost Index



Source: RSMeans, Heavy Construction Cost Data, 20th Annual Edition, 2006.

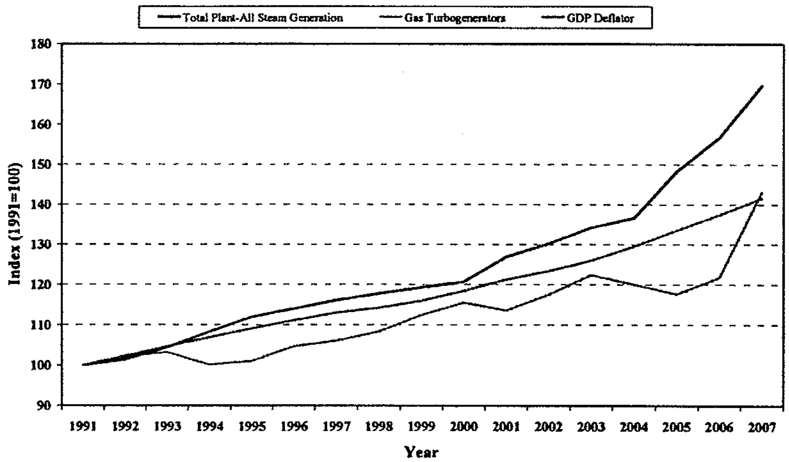
The Handy-Whitman Index© publishes detailed indices of utility construction costs for six regions, broken down by detailed component costs in many cases. Figures 17 through 19 show the evolution of several of the broad aggregate indices since 1991 compared with the general inflation index (GDP deflator).[18] The index numbers displayed on the graphs are for January 1 of each year displayed.

Figure 17 displays two indices for generation costs: a weighted average of coal steam plant construction costs (boilers, generators, piping, etc.) and a stand-alone cost index for gas combustion turbines.

As seen on Figure 17, steam generation construction costs tracked the general inflation rate fairly well through the 1990s, began to rise modestly in 2001, and increased significantly since 2004. Between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units increased by 25 percent—more than triple the rate of inflation over the same time period. The cost of gas turbogenerators (combustion turbines), on the other hand, actually fell between 2003 and 2005. However, during 2006, the cost of a new combustion turbine increased by nearly 18 percent—roughly 10 times the rate of general inflation.

[18] Used with permission. See Handy-Whitman© Bulletin, No. 165 for detailed data breakouts and regional values for six regions: Pacific, Plateau, South Central, North Central, South Atlantic and North Atlantic. The Figures shown reflect simple averages of the six regions.

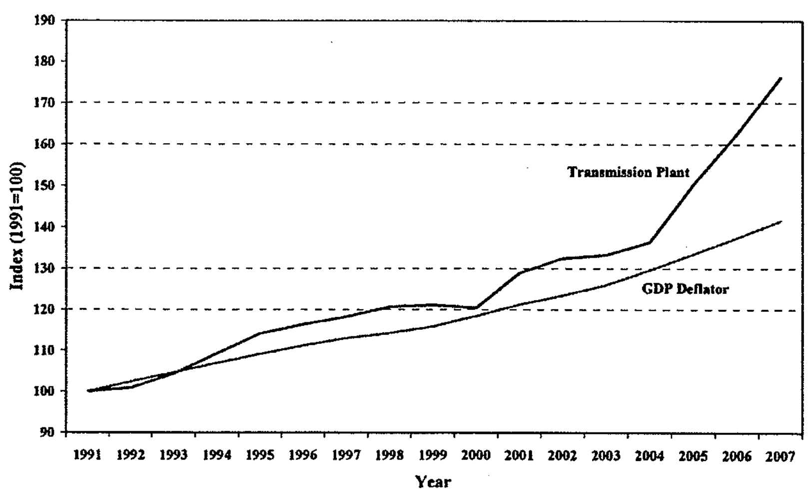
Figure 17
National Average Generation Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.
Simple average of all regional construction and equipment cost indices for the specified components.

Figure 18 displays the increased cost of transmission investment, which reflects such items as towers, poles, station equipment, conductors and conduit. The cost of transmission plant investments rose at about the rate of inflation between 1991 and 2000, increased in 2001, and then showed an especially sharp increase between 2004 and 2007, rising almost 30 percent or nearly four times the annual inflation rate over that period.

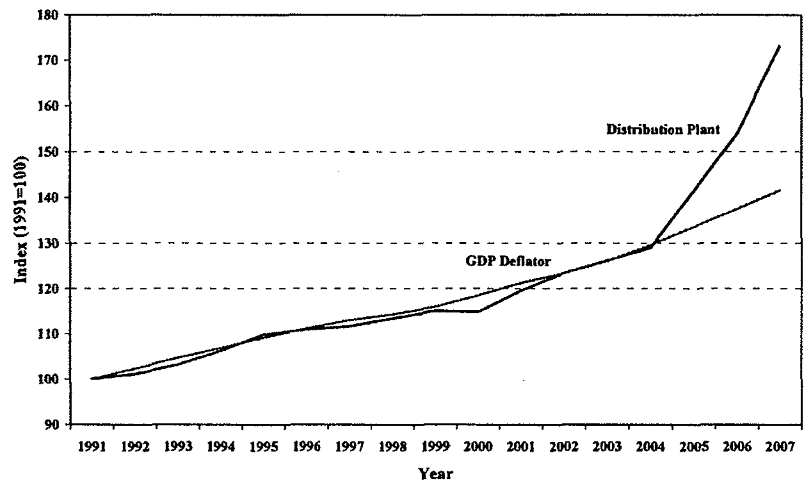
Figure 18
National Average Transmission Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional transmission cost indices.

Figure 19 shows distribution plant costs, which include poles, conductors, conduit, transformers and meters. Overall distribution plant costs tracked the general inflation rate very closely between 1991 and 2003. However, it then increased 34 percent between January 2004 and January 2007, a rate that exceeded four times the rate of general inflation.

Figure 19
National Average Distribution Cost Index



Sources: The Handy-Whitman© Bulletin, No. 165, and the U.S. Bureau of Economic Analysis.
Simple average of all regional distribution cost indices.

Comparison with Energy Information Administration Power Plant Cost Estimates

Every year, EIA prepares a long-term forecast of energy prices, production, and consumption (for electricity and the other major energy sectors), which is documented in the *Annual Energy Outlook* (AEO). A companion publication, *Assumptions to the Annual Energy Outlook*, itemizes the assumptions (*e.g.*, fuel prices, economic growth, environmental regulation) underlying EIA's annual long-term forecast. Included in the latter document are estimates of the "overnight" capital cost of new generating units *(i.e.,* the capital cost exclusive of financing costs). These cost estimates influence the type of new generating capacity projected to be built during the 25-year time horizon modeled in the AEO.

The EIA capital cost assumptions are generic estimates that do not take into account the site-specific characteristics that can affect construction costs significantly.[19] While EIA's estimates do not necessarily provide an accurate estimate of the cost of building a power plant at a specific location, they should, in theory, provide a good "ballpark" estimate of the relative construction cost of different generation

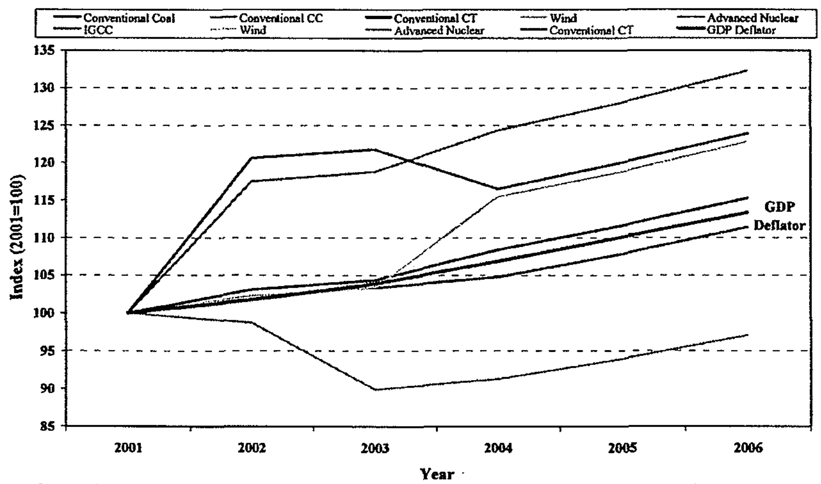
[19] EIA does incorporate regional multipliers to reflect minor variations in construction costs based on labor conditions.

technologies at any given time. In addition, since they are prepared annually, these estimates also should provide insight into construction cost trends over time.

The EIA plant cost estimates are widely used by industry analysts, consultants, academics, and policymakers. These numbers frequently are cited in regulatory proceedings, sometimes as a yardstick by which to measure a utility's projected or incurred capital costs for a generating plant. Given this, it is important that EIA's numbers provide a reasonable estimate of plant costs and incorporate both technological and other market trends that significantly affect these costs.

We reviewed EIA's estimate of overnight plant costs for the six-year period 2001 to 2006. Figure 20 shows EIA's estimates of the construction cost of six generation technologies—combined-cycle gas-fired plants, combustion turbines (CTs), pulverized coal, nuclear, IGCC, and wind—over the period 2001 to 2006 and compares these projections to the general inflation rate (GDP deflator). These six technologies, generally speaking, have been the ones most commonly built or given serious consideration in utility resource plans over the last few years. Thus, we can compare the data and case studies discussed above to EIA's cost estimates.

Figure 20
EIA Generation Construction Cost Estimates



Sources: Data collected from the Energy Information Administration, *Assumptions to the Annual Energy Outlook 2002 to 2007* and from the U.S. Bureau of Economic Analysis.

The general pattern in Figure 20 shows a dramatic change in several technology costs between 2001 and 2004 followed by a stable period of growth until 2006. The two exceptions to this are conventional coal and IGCC, which increase by a near constant rate each year close to the rate of inflation throughout the period. The data show conventional CC and conventional CT experiencing a sharp increase between 2001 and 2002. After this increase, conventional CC levels off and proceeds to increase at a pace near inflation, while conventional CT actually drops significantly before 2004 when it too levels near the rate of inflation. The pattern seen with nuclear technology is near to the opposite. It falls dramatically until about 2003 and then increases at the same rate as the GDP deflator. Lastly, wind moves close to inflation until 2004 when it experiences a one-time jump and then flattens off through 2006.

These patterns of cost estimates over time contradict the data and findings of this report. Almost every other generation construction cost element has shown price changes at or near the rate of inflation throughout the early part of this decade with a dramatic change in only the last few years. EIA appears to have reconsidered several technology cost estimates (or revised the benchmark technology type) in isolation between 2001 and 2004, without a systematic update of others. Meanwhile, during the period that overall construction costs were rising well above the general inflation rate, EIA has not revised its estimated capital cost figures to reflect this trend.

EIA's estimates of plant costs do not adequately reflect the recent increase in plant construction costs that has occurred in the last few years. Indeed, EIA itself acknowledges that its estimated construction costs do not reflect short-term changes in the price of commodities such as steel, cement and concrete.[20] While one would expect some lag in the EIA data, it is troubling that its most recent estimates continue to show the construction cost of conventional power plants increasing only at the general rate of inflation. Empirical evidence shows that the construction cost of generating plants—both fossil-fired and renewable—is escalating at a rate well above the GDP deflator. Even the most recent EIA data fail to reflect important market impacts that are driving plant construction costs, and thus do not provide a reliable measure of current or expected construction costs.

[20] *Annual Energy Outlook 2007*, U.S. Energy Information Administration, p. 36.

Petitioner's Exhibit PWP-5
Northern Indiana Public Service Company
Cause No. 43526

Conclusion

Construction costs for electric utility investments have risen sharply over the past several years, due to factors beyond the industry's control. Increased prices for material and manufactured components, rising wages, and a tighter market for construction project management services have contributed to an across-the-board increase in the costs of investing in utility infrastructure. These higher costs show no immediate signs of abating.

Despite these higher costs, utilities will continue to invest in baseload generation, environmental controls, transmission projects and distribution system expansion. However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. The overall impact on the industry and on customers, however, will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases. In the long run, customers ultimately will pay for higher construction costs—either directly in rates for completed assets of regulated companies, less directly in the form of higher energy prices needed to attract new generating capacity in organized markets and in higher transmission tariffs, or indirectly when rising construction costs defer investments and delay expected benefits such as enhanced reliability and lower, more stable long-term electricity prices.

Petitioner's Exhibit TAD-1

NORTHERN INDIANA PUBLIC SERVICE COMPANY

IURC CAUSE NO. 43526

VERIFIED DIRECT TESTIMONY

OF

TIMOTHY A. DEHRING

SENIOR VICE PRESIDENT, ENERGY DELIVERY

SPONSORING PETITIONER'S EXHIBITS TAD-2 THROUGH TAD-8

VERIFIED DIRECT TESTIMONY OF TIMOTHY A. DEHRING

Q1. Please state your name and business address.

A1. My name is Timothy A. Dehring. My business address is 801 East 86th Street, Merrillville, IN 46410.

Q2. By whom are you employed and in what capacity?

A2. I am employed by Northern Indiana Public Service Company ("NIPSCO" or the "Company") as Senior Vice President, Energy Delivery. In this role, I oversee gas and electric transmission and distribution operations throughout NIPSCO's service territory. I have responsibility for the safety of my workforce; the delivery of service to NIPSCO's customers; the restoration of electric service interruptions related to transmission and distribution systems; and the design, integrity and reliability of the electric distribution infrastructure.

Q3. What is your educational background?

A3. I graduated with a Bachelor of Science Degree in Civil Engineering in 1981 from the University of Wisconsin at Milwaukee. I also have a Masters Degree in Management from Purdue University, awarded in 1986.

Q4. Please describe your professional experience.

A4. I began my employment with NIPSCO in April 1982 as an electrical engineer. Since that time, I have held various positions with NIPSCO, including Engineering Supervisor, Operating Superintendent in the Fort Wayne area, Operations Manager for the East Region of NIPSCO's service territory, Manager of Operations Planning and Manager of

Service Delivery and Resource Planning, Director of Construction, and Vice President, Service Delivery. From January 2004 until July 2008, I served as the General Manager, Indiana Operations. In July 2008, I was appointed to my present position.

Q5. Have you previously testified before this or any other regulatory commission?

A5. Yes. I provided testimony in the Indiana Utility Regulatory Commission's Cause No. 42194.

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to: (1) describe NIPSCO's electric transmission system and the impact of changes in electric transmission system planning approaches; (2) discuss NIPSCO's implementation of the Federal Energy Regulatory Commission's ("FERC") Seven-Factor Test; (3) describe NIPSCO's electric distribution system, the main drivers of investment, planned capital projects, the Company's electric reliability programs, specific detail in the areas of pole and underground cable inspection and replacement, vegetation management, additional maintenance programs associated with electric transmission towers and substations and specific needs of the electric meter infrastructure; (4) outline the Company's planned investment in work management technologies; (5) describe new electric safety programs; and (6) describe how upcoming employee retirements will impact the transmission and distribution operations segment at NIPSCO.

I. <u>NIPSCO'S ELECTRIC TRANSMISSION SYSTEM</u>

Q7. Please describe NIPSCO's electric transmission system.

A7. The NIPSCO electric transmission system consists of 354 circuit miles of 345kV, 763 circuit miles of 138kV and 1,660 circuit miles of 69kV transmission lines. In addition, NIPSCO has 51 transmission substations. NIPSCO is interconnected with five of our neighboring utilities. The Company has transmission interconnects with American Electric Power or its affiliates, at the 345kV, 138kV, and 69kV voltages totaling 5,583 megavolt ampere ("MVA") of capability. NIPSCO also interconnects with Commonwealth Edison at 345kV and 138kV totaling 5,761 MVA of capability, and with Duke Energy Indiana at 345kV, 138kV and 69kV totaling 1,195 MVA of capability. NIPSCO has a single 138kV interconnection with both Ameren and International Transmission Company ("ITC") with 239 MVA of capability on the Ameren tie and 273 MVA of capability on the ITC tie. The total interconnection capability for NIPSCO is 13,054 MVA.

Q8. Please describe the historical electric transmission system planning process at NIPSCO?

A8. The NIPSCO electric transmission system was primarily designed and operated to reliably serve NIPSCO's native load. To meet the needs of its retail customers, electricity generated within the NIPSCO service territory had to be transmitted to customers within the NIPSCO system. The transmission system was largely "self-sufficient" except when internal generation was unable to meet internal demand, at which time power had to be brought into the NIPSCO system (imported) from outside its service territory. Just as NIPSCO's transmission system was designed to handle the demands of the NIPSCO service territory, the transmission systems of neighboring utilities were designed to handle their internal needs. Agreements between neighboring utilities allowed for the importation of power in those situations where a utility could not meet the needs of its service territory with internal generation for any reason. Although not its primary purpose, these interconnections also provided for economic exchange of power with the neighboring interconnected utilities and contributed to the stability of the interconnection and provided frequency support.

Q9. What impacts has the introduction of Regional Transmission Organizations had in your electric transmission system planning approaches?

A9. Open access, Regional Transmission Organization ("RTO") control, and other market activities [e.g. the day ahead and real-time power markets within RTOs, including the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO")], resulted in NIPSCO's transmission system being used differently than it was historically designed and constructed to achieve. NIPSCO had designed and developed its historical planning models to primarily address NIPSCO's own facilities. With the advent of the RTO, new planning models which address all transmission facilities inside, as well as facilities outside the RTO footprint that are necessary to maintain reliability within the RTO footprint were developed. The RTO now relies upon each of the transmission owners, including NIPSCO, to feed system data from its own internal planning processes to the RTO planning processes. That information, combined with data otherwise collected by the RTO and assistance from the transmission owners, provides the RTO with the information it needs to plan the transmission system across the entire RTO footprint consistent with FERC and North American Electric Reliability Corporation ("NERC") planning requirements. These developments have increased NIPSCO's transmission planning requirements and broadened our models.

Q10. Has NIPSCO experienced any cost savings as a result of these developments in the electric transmission system planning process?

A10. No. The internal transmission planning process is still needed to address needs of the NIPSCO system and our retail customers. The results of the Company's internal analysis are then provided to the RTO for the RTO to integrate NIPSCO's needs with the remainder of the RTO needs. That step evaluates whether other RTO projects might be more cost beneficial in addressing NIPSCO needs and whether a NIPSCO project might be more beneficial in addressing other RTO needs. The end result is that there are no cost savings to NIPSCO in determining the most cost beneficial transmission plan across the RTO footprint.

II. <u>FERC SEVEN-FACTOR TEST</u>

Q11. Are you familiar with the FERC Seven-Factor Test?

A11. Yes, I am. The Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. requires NIPSCO to implement FERC's Seven-Factor Test set forth in FERC Order No. 888 ("FERC Seven-Factor Test").[1]

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[1] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, Docket No. RM95-8-000, 75 FERC 61,080, Order No. 888 Final Rule, FERC Stats. & Regs. ¶ 32,514 at 33,145 (April 24, 1996) (Order 888).

Q12. What does the FERC Seven-Factor Test accomplish?

A12. The FERC Seven-Factor Test analyzes the electric delivery system under seven different views to determine how the various components of the electric delivery system should be classified between transmission or distribution.

Q13. Did NIPSCO utilize the FERC Seven-Factor Test to determine the classification of its transmission and distribution facilities?

A13. Yes. NIPSCO retained Stone & Webster Management Consultants, Inc. ("Stone & Webster") to assist in performing the FERC Seven-Factor Test. Stone & Webster's application of the FERC Seven-Factor Test is described more fully by NIPSCO Witness Robert Greneman from Stone & Webster.

Q14. Did NIPSCO use the results from the Stone & Webster analysis to classify the Company's electric delivery system facilities as transmission or distribution facilities?

A14. Yes. After reviewing the results of the Stone & Webster study, NIPSCO determined that all of NIPSCO's electric delivery system facilities rated 69 kV and above, networked or operated as radial, should be classified as transmission. The Company also concluded that all of NIPSCO's electric delivery system facilities rated below 69 kV should be classified as distribution. This resulted in $108,644,289 of transmission assets being re-classified as distribution assets and $14,599,077 of distribution assets being re-classified as transmission as discussed in more detail by Mr. Greneman and NIPSCO Witness Mitchell E. Hershberger.

III. NIPSCO'S ELECTRIC DISTRIBUTION SYSTEM

Q15. Please provide an overview of the NIPSCO electric distribution system.

A15. NIPSCO serves more than 450,000 customers in Northern Indiana, primarily through more than 800 distribution circuits. These circuits operate at a nominal voltage of 34,500 volts and 12,470 volts, and radiate from approximately 250 distribution substations. There are more than 8,000 miles of overhead line, with about 2,100 miles of underground cable.

Q16. What are the circumstances and criteria that drive investment in the electric distribution system?

A16. There are four (4) primary areas driving NIPSCO's investment in its electric distribution system:

- Growth – adding new infrastructure to serve newly connected customers. New infrastructure can be as simple as a service cable and meter installation or as extensive as the development of an entire area. Growth can also include replacement of existing facilities of insufficient capacity to serve the new customer.
- Public Improvements – relocating or re-installing existing facilities to accommodate state or local improvement projects such as roads, bridges, or traffic signals.
- Capacity Betterments – installing higher capacity equipment to meet the overall demands of an expanding economy. These investments are not driven by one customer or development but rather to serve growing needs in particular regions.

- Infrastructure Replacement – installing new equipment to replace equipment that no longer delivers adequate levels of service and reliability. Many of these replacements are made and funded through programs NIPSCO initiated to test and evaluate existing equipment, which optimizes timing and method of construction. Two of the Company's larger programs are the inspecting of wood poles and 15 kV underground cables.

Q17. Does NIPSCO focus on the reliability of its electric distribution assets?

A17. Yes. NIPSCO, like many utilities within Indiana and around the country, is increasingly sensitive to the age of its facilities. My testimony will describe additional steps NIPSCO is taking to ensure the continued reliable and safe operation of the system.

Q18. How does NIPSCO plan for reliability associated with system capacity and infrastructure integrity?

A18. Ongoing capacity planning serves to continually monitor the electric system to ensure NIPSCO meets growing loads with proper voltage and current carrying capabilities. This is accomplished through actual and simulated load studies, along with forecasting of load growth on a five to ten-year horizon. Improvements are prioritized to address system reliability in the most effective manner, balancing system utilization, service reliability, and public safety. The Company identifies and prioritizes infrastructure replacement projects through an analysis of useful equipment life, testing, and trending.

Q19. Please describe the Company's wood pole inspection program.

A19. NIPSCO has over 300,000 wood poles in its electric distribution system. To properly maintain and assess the integrity of these critical assets, the Company employs a pole inspection and treatment program. Approximately 10% of the wood poles, or approximately 30,000 per year, are subject to inspection. The inspection and treatment process first involves a physical inspection of the pole. For poles greater than 10 years old, if sufficient strength remains in the pole, it is treated with a preservative that typically extends the pole life an additional 10 years when compared to an untreated pole.

On average, this inspection and treatment process costs approximately $21 per pole, thus extending its life 10 years for about $2 per year. The annual inspection and treatment investment is about $680,000. Poles that no longer maintain sufficient structural strength due to decay or other mechanical damage are rejected by the inspector and scheduled for replacement. This process facilitates an extension to a pole's life for a modest investment while the replacement capital is targeted at poles that must be replaced. On average, about 1,200 poles are identified for replacement each year.

The overall benefits of this pole inspection and treatment approach include:

- Regular assessment of the pole plant integrity;
- Targeted capital replacements for those poles in need;
- Useful life extended for non-replaced poles;
- An opportunity to mitigate potential safety hazards, such as missing down-guy guards; and

– Improved reliability through planned pole replacements.

Q20. Please describe NIPSCO's underground cable program.

A20. In many respects, the underground cable program is similar to the Company's wood pole inspection program. NIPSCO has approximately 2,100 miles of underground 15 kV cable. Approximately 705 miles is unjacketed cable installed from the early 1970s to the end of 1991.

While there are no like opportunities available to extend the useful life of underground electric cable though treatment, NIPSCO's cable inspection and replacement program uses a similar approach of inspection, followed by targeted replacement of those sections at highest risk of failure. Unjacketed underground electric cables tend to deteriorate faster than the more modern jacketed cables. This deterioration of the cable insulation causes failures and resulting outages. Over 90% of NIPSCO's cable failures come from the unjacketed cable.

The core of the underground cable inspection and replacement program is based on the use of a non-destructive test to determine if a cable has reached the end of its useful service life. This non-destructive testing approach was piloted briefly in 2006 and again in 2007 with favorable results. As a result, beginning with 2008, NIPSCO has launched a fifteen (15) year program to test all of its unjacketed underground cable and replace those sections that indicate problems.

Q21. What other types of maintenance programs are in place at NIPSCO to ensure electric system reliability?

A21. NIPSCO has put in place a comprehensive set of proactive substation, transmission, and distribution maintenance programs targeted at reliability.

Q22. Would you summarize NIPSCO's electric substation and transmission maintenance programs?

A22. NIPSCO's substation maintenance programs include predictive, preventive, and corrective elements. From a predictive standpoint, quarterly aerial and annual ground infrared surveys are conducted on substation equipment to assess if areas of unusual heating are noticed. Additionally, a diagnostic oil analysis is completed annually on transformers. From a preventive standpoint, substation equipment is monitored on a monthly basis across multiple operational indicators. All operational inspections are electronically recorded and any required corrective maintenance activities are identified for completion. Subject to system clearance opportunities, key maintenance activities are typically completed within a month.

The Company's transmission system control and relay programs are focused on regular maintenance, ongoing electric system monitoring and continuous improvement. NIPSCO schedules relay maintenance according to the relay "Inspection and Functional Test" program. This program provides for inspection frequencies of two to six years. NIPSCO developed this process by analyzing years of relay maintenance records and trouble calls. NIPSCO continuously improves its protective relaying schemes by replacing older electro-mechanical protection schemes with modern microprocessor based relays. These relays provide internal diagnostic testing and self-checking capabilities. Additionally, these relays provide greater details for evaluating relay performance and fault location/analysis.

NIPSCO invested heavily in diagnostic tools such as digital fault recorders and sequence of event recorders that enable engineers to evaluate and analyze system protection more thoroughly than ever before. All system disturbances are fully investigated to determine how the particular schemes responded. Any abnormalities can be quickly identified and field engineers are dispatched to provide on-sight investigations. During such situations, the Company performs full calibration and functional tests on suspect relays. NIPSCO inspects its electric transmission towers and poles at five-year intervals for structural concerns and for the integrity of conductor attachments. This inspection is completed by a combination of climbing and specialized helicopter patrols. Most of the problems discovered relate to conductor and static wire support devices with only a small number of structural concerns identified. All such identified transmission tower and pole remediation work has been completed.

Q23. Would you summarize NIPSCO's electric distribution maintenance programs?

A23. NIPSCO's electric distribution maintenance program includes periodic inspections of padmount transformers, pole mounted reclosers and voltage regulators, switched capacitors, ground mounted substations, and other underground equipment. This program also includes the remedial work necessary to repair or replace minor plant items found to be deficient from inspection criteria. In addition to these maintenance activities, we have a robust vegetation management plan and, as discussed below, have made significant reliability-based enhancements in this area.

Q24. Please address NIPSCO's efforts to improve transmission reliability through vegetation management.

A24. NIPSCO has an Integrated Vegetation Management ("IVM") program for maintaining vegetation on its electric transmission corridors. The IVM objective is to eliminate woody species on transmission corridors, provide access for inspection and maintenance, minimize damage to desirable species, use vegetation management techniques that pose low environmental risk, protect endangered species and habitats, and utilize the most cost effective techniques. The result is the conversion of woody species to grasses, which do not require on-going cutting.

The Company's IVM program has been developed and is managed by in-house company professionals within the Forestry Operations department. IVM was first implemented at NIPSCO in 1997 and underwent review and revision in 2001 and again in 2003. Prior to the introduction of IVM in 1997, NIPSCO utilized a 6-year cycle of brush hog mowing of brush on the transmission corridor floor. Approximately 80% of NIPSCO's electric transmission corridors' managed brush acres have been transitioned to IVM.

On corridors that have not yet been transitioned to IVM, trees on the corridor floor are monitored and pruned as necessary until IVM can be implemented. In addition to the conversion of the corridor floor to IVM, side pruning of trees along corridor edges is employed to ensure that no trees or branches encroach into the corridor. During side pruning work, NIPSCO performs a visual inspection of trees alongside and off of the corridor to identify hazardous tree conditions that could result in a risk of tree failure and line contact. The Company either prunes for safe clearance or removes hazardous trees.

Q25. Are there standards that govern your transmission IVM program?

A25. Yes. NERC's reliability standard "FAC-003-1 - Transmission Vegetation Management Program" ("TVMP") became effective on April 7, 2006. This standard is applicable to all bulk electric transmission circuits greater than 200kV and certain other critical circuits greater than 200kV. This new standard requires, among other things:

- Rigorous vegetation inspection schedules.
- Documentation and planning for vegetation management maintenance.
- Mandatory reporting of certain vegetation caused outages.
- Development and enforcement of standards for minimum vegetation clearances to conductors.
- Development of comprehensive TVMPs by the owners of electric transmission facilities.
- Creation of mitigation plans by the owners of electric transmission facilities where easement, land rights, or other restrictions adversely affect compliance with their TVMPs.

Compliance with this standard has resulted in an increase in the costs of clearing trees and vegetation growth from transmission corridors

Q26. Are there similar improvements being made in the distribution vegetation management program?

A26. Yes, mainly in the area of tree trimming cycle time. In general, electric interruptions tend to increase should the cycle time of vegetation management increase. An analysis of NIPSCO's outage-related data indicated that this relationship was most dramatic in cycle times greater than four (4) years. The cost of clearing work can also be related to the cycle time. Longer cycle times result in considerably more tree growth removal at the time of trimming. In these cases, the tree experiences more stress making it susceptible to disease. Additionally, the tree will enter a rapid tree replacement growth period, growing back towards the electric conductors faster than with more moderate removal amounts. Lastly, longer cycles negatively impact customer satisfaction as the more dramatic cuts visually stand out. As a result of all of these factors, NIPSCO made a decision in 2004 to move to a four (4) year tree trimming cycle from the five (5) to seven (7) year cycles it previously used.

Q27. How has NIPSCO transitioned to shorter tree trim cycle times?

A27. The Company implemented a circuit-based trim schedule that is prioritized by interruption experience and cycle time, and moved to the four (4) year cycle. At the same time, NIPSCO instituted changes in its line clearance approach and specifications with contractors. Fixed cost bids are now awarded to contractors via bundles of circuits

(circuits commencing from the same substation) as opposed to a grid based time and material approach. By following this approach, we have experienced a much quicker line clearing response to tree-related interruption experiences. By using this fixed bid approach, the Company can focus its oversight of the contracted work on trim quality and the resulting reliability impacts.

NIPSCO chose a ramp-up trim schedule to best utilize tree trimming resource availability and to create smoother work flow for future line clearing. The Company conducts an annual circuit performance analysis to determine those circuits that, regardless of cycle time, have had a higher experience of interruptions. NIPSCO surveys those circuits, identifies sources of tree interruptions and performs remedial work.

Q28. Please describe NIPSCO's hazard tree identification and trimming process.

A28. The Company now practices hazard tree identification trimming and/or removal. This process identifies trees that have a high risk of causing reliability issues, due to age, health, or location. NIPSCO also increased efforts to remove the canopy (overhanging) tree limbs on 3-phase distribution conductors. Data and field observations show that many tree-caused interruptions result from falling limbs from the side and above, as opposed to tree growth from below the conductors.

Q29. How has NIPSCO's overall investment in vegetation management increased over the past few years due to these transmission and distribution improvements?

A29. The Company's annual costs for these programs have increased because of the additional work I described and by inflation in contractor costs. Increases in contractor labor rates rose 13% from 2005 to 2008. Equipment price increases grew 20% over this same period. Overall, historical and forward looking vegetation management expenditures for transmission and distribution line clearance work are shown in Petitioner's Exhibit TAD-2. A pro-forma adjustment for this increased spending is represented in Petitioner's Exhibit LEM-2.

IV. ELECTRIC METERING

Q30. Are you generally familiar with NIPSCO's proposal to require that customers receiving service under Rate 523 have meters capable of measuring demand?

A30. Yes.

Q31. Do all Customers on Proposed Rate 523 currently have meters capable of measuring demand?

A31. No. Approximately, 2,351 customers currently have KWh only meters, which are not capable of measuring demand.

Q32. Please explain why Customers on Proposed Rate 523 require a meter capable of measuring demand.

A32. As explained in more detail by NIPSCO Witness Frank Shambo, Proposed Rate 523 is for general service customers with demands that range from 10 KW to 300 KW. It is designed as a demand and energy rate to bill costs to customers based upon how they use the NIPSCO system.

Q33. What is NIPSCO's plan regarding those customers that are currently without demand meters?

A33. NIPSCO's plan is to replace the 2,351 KWh only meters with manual-read Interval Demand Recorders ("IDRs") in 2009. If NIPSCO is unable to complete this installation, NIPSCO will not assess any demand charges on any customer that does not have a demand meter.

Q34. Please identify the installed meter cost associated with replacing the KWh only meters with manual-read IDRs for Proposed Rate 523.

A34. The installed meter cost budgeted for 2009 is approximately $1.9 million.

Q35. Are there any additional costs associated with deployment of IDRs?

A35. Yes. Incremental costs will be incurred for the hand-held devices and labor required to physically read the meters and to make the required upgrades to the software application used at NIPSCO to capture data from IDR type meters and to NIPSCO's Customer Information System so that IDR meter information can be billed. These costs have not been included in NIPSCO's budget for 2009 or beyond.

Q36. Is NIPSCO seeking recovery of the costs of the IDR in this rate case?

A36. No. NIPSCO intends to seek recovery in its Demand Side Management Alternative Regulatory Plan, which is more fully described by Mr. Shambo.

Q37. Please explain the benefits of switching from KWh only meters to IDRs.

A37. The benefits include improved load research and forecasting capabilities, the collection of demand information, as well as enhanced customer service.

Q38. Please explain the improvement in load research and forecasting.

A38. KWh only meters do not provide information to the Company about the Customer's load patterns. IDRs can track the Customer's load pattern on an interval basis as small as 5 or 15 minutes. This additional interval data can be used to measure the time and magnitude of the Customer's daily/monthly/annual peak, to develop load shapes for a specific time period, and to store historical load data for customers on NIPSCO's system. The additional load research data obtained from IDRs can also assist NIPSCO in exploring time-of-use rates.

Q39. What benefits will customers on the Proposed Rate 523 see from IDR metering?

A39. Customer bills will specifically show how they use NIPSCO's system and consume electricity.

V. <u>WORK MANAGEMENT TECHNOLOGIES</u>

Q40. Please describe NIPSCO's work management system.

A40. NIPSCO is nearing the completion of a multi-year initiative to implement a comprehensive work management system. Investment in this technology is critical to maintaining and improving customer service and reliability. The work management system will utilize the MAXIMO software application as its core work and asset management solution. NIPSCO's field employees will link to MAXIMO through a new mobile dispatch application and wireless enabled computer in the vehicle. NIPSCO's Geographic Information System ("GIS") will also be linked to MAXIMO. GIS is a mapping system technology that creates intelligent maps through which sophisticated planning and analysis can be performed instantaneously.

Q41. Why is NIPSCO making this technology investment now?

A41. The decision to implement the work management technologies was driven by many factors. Historically, NIPSCO deployed small, functionally specific work management applications. Few of these were integrated and some operational areas had little technology beyond local spreadsheets to track work and maintenance requirements. The current mobile dispatch system in place for service work is in need of replacement. NIPSCO did not have a mobile connection to other construction and maintenance employees, making job status information hard to obtain and therefore, difficult to communicate to our customers.

Q42. What are the most significant benefits NIPSCO anticipates will result from the new work management system?

A42. The most significant benefits from these new technologies will be in the area of customer service, safety, and reliability. The link between GIS and MAXIMO will result in maps that are more current, thereby enhancing NIPSCO's damage prevention efforts. Visual representation of service truck locations in the dispatch center will aid in emergency response. Comprehensive and timely notification of maintenance work will aid in its completion and the resultant improvement in the integrity of our infrastructure. The automated linkage between GIS, mobile dispatch, and the Company's electric outage restoration system also is expected to enhance the Company's storm restoration capabilities. Finally, enhanced information on job status and work crew availability will support improvements in meeting service appointments and in communicating job status information to our customers.

VI. NEW ELECTRIC SAFETY PROGRAMS

Q43. Please identify the safety-related improvements that NIPSCO plans to implement.

A43. NIPSCO continuously looks for opportunities to improve employee safety through hazard mitigation, process and work environment improvements. The electric industry recognizes that one of the more significant hazards employees face is exposure to electric arc flash. As a result, National Electric Safety Code standards, which NIPSCO is required to adhere to, have been upgraded to require electrical workers, beginning January 1, 2009, to wear Fire Retardant ("FR") electric arc rated clothing when performing work on energized exposed electrical conductors. The prior standard required only that the employer prohibit certain types of garments, *i.e.* nylon, rayon, acetate or polyester which could increase the extent of injury.

NIPSCO has approximately 800 employees in its electric generation, transmission and distribution areas that will be impacted by this standard. In 2008, the Company will spend $650,000 in initial purchases to provide these FR garments for the impacted employees. In preparation of compliance to the 2009 date, NIPSCO spent approximately $10,000 in training and software costs to conduct a risk assessment and determine the extent of arc rated FR clothing for each work area. Since FR garments lose their effective arc rating properties over time due to repeated cleaning and/or fabric tears, an annual garment replacement program will cost 40% of the initial cost, or $260,000 per year after 2008.

Q44. Are there any other safety programs implemented by the Company?

A44. Yes. The Occupational Safety and Health Administration ("OSHA") joined with representatives from the power transmission and distribution industry, as well as trade and labor representatives, to form the OSHA Strategic Partnership ("OSP"). The primary goal of OSP is to reduce the number of fatalities, injuries, and illnesses in the electric utility industry. One outcome from the OSP was the publication of electric line best work practices.

NIPSCO and its Physical Bargaining Union, the United Steelworkers of America, Local Union 12775, District 7, have made a commitment to work together to make improvements in its electric line safety program. In doing so, we have put plans in place to adopt the OSP's best work practices for use at NIPSCO. Primarily, these work practices focus on effective pre-job briefings, the proper use of line cover and rubber personal protective equipment, the use of qualified observers while critical live line tasks are being performed, and a system of field safety performance observations. Additionally, NIPSCO has ongoing efforts to update NIPSCO's electric line policies and procedures, upgrade the apprentice program, and enhance the Company's continuing education for electric line journeymen.

To properly implement the field safety performance observation process, an additional three (3) linemen will be required. This represents an initial deployment of six (6) linemen involved in the field observation process for the second half of 2008. Beginning in 2009, this annual need will fall to three (3) linemen.

Q45. Can you summarize the additional cost required for these two safety initiatives?

A45. Petitioner's Exhibit TAD-3 shows the additional costs required to implement these safety initiatives. The need for the additional three linemen was included in the linemen staffing model (Petitioner's Exhibit TAD-4) used for the Aging Workforce pro-forma adjustment. The costs associated with the incremental three linemen are shown in Petitioner's Exhibit TAD-3. Additionally, the pro-forma adjustment that results from these additional safety costs is shown in Petitioner's Exhibit LEM–2.

VII. AGING WORKFORCE

Q46. Please describe the challenges that upcoming employee retirements will present in electric transmission and distribution?

A46. NIPSCO Witness Robert Campbell describes the Company's overall efforts to address the impacts of our aging workforce. I will address this issue as it relates to electric transmission and distribution. In the electric transmission and distribution areas, NIPSCO focuses its aging workforce strategies on six positions, electric linemen, electric metermen, substation electricians, dispatcher operators, first line supervisors, and engineers.

While NIPSCO has seen steady retirements over the past few years in the electric linemen classification, the replacement of these positions has caused rapid growth in the number of apprentice linemen. The Company filled additional jobs beyond anticipated retirement levels in 2007 and will continue to do so over the next few years. NIPSCO also determined that approximately 50 apprentice linemen is near the maximum the Company can support with on the job training from journeymen. The high number of apprentice linemen relative to journeymen has also caused the need to increase consumption of planned overtime in the linemen ranks.

The Company expects the retirement of electric metermen to increase in the 2009 to 2011 period. As this is a three year apprentice position, NIPSCO began filling these positions ahead of expected retirement dates so that the Company has a sufficient complement of trained electric metermen as advanced meter technologies become more common.

In the substation electrician classification, about one-third of the qualified journeyman electricians are eligible to retire, and are predicted to do so within the next five years. Once again, NIPSCO is currently filling these positions in advance of expected retirement dates to mitigate the impact of the four-year apprentice training cycle on the number of qualified journeyman on-hand. As with the lineman position, an appropriate balance must be maintained between journey and apprentice electricians.

The dispatcher operator retirement situation is more dramatic, in spite of the fact that there is only a one-year training cycle, as roughly 80% of these employees are currently eligible to retire. The Company has been filling these positions in advance at an accelerated rate, and have four to five employees in training at any given time. The dispatcher operator position is a desirable option for senior employees. Several of the employees in this category who are eligible to retire are well beyond the normal retirement age of fifty-five, making it the most senior bargaining unit group in NIPSCO. Because of the significance of the additional training demand, NIPSCO hired a dedicated trainer to assist the Company through this challenging period.

NIPSCO's historic approach of filling first line supervisor and engineer positions as retirements occur is no longer adequate. With fewer experienced first line supervisors and engineers on staff to train new hires, it is increasingly difficult to rely on "on the job" training for the new professionals.

Q47. What operational and staffing strategies did NIPSCO implement to address these challenges?

A47. In general, NIPSCO has adopted a more proactive approach of filling jobs ahead of the anticipated departure dates of retirees. This approach helps in leveraging the training talents of our experienced workforce before they retire and also allows for more formal training experiences. A five year staffing plan has been established for each of the critical positions cited above.

For electric linemen, this plan contains an aggressive start of early replacements in 2007 and the four year apprentice program of formal training. The process also puts in place a long term strategy to reduce the occurrence of planned overtime that is driven in large part by the heavy loading of year 1 and year 2 apprentice linemen. The five year staffing plan also integrates the need for the three additional electric linemen for the safety initiative described earlier in my testimony.

Petitioner's Exhibit TAD-4 summarizes the five year staffing plan for electric linemen and shows the calculation of incremental staffing beyond the 2007 test year. This exhibit also separates out the three electric linemen required for the safety initiative as the cost for these positions is included in a separate pro-forma adjustment for safety. The five year staffing plan for electric metermen, substation electricians, and dispatcher operators works similarly to that just described for electric linemen, with the exception of the need to mitigate the surplus planned overtime.

The staffing strategies for electric metermen, substation electricians, and dispatcher operators are shown in Petitioner's Exhibit TAD-5, TAD-6 and TAD-7, respectively. For first line supervisors and engineers, the five year staffing plan targets a one year training period and therefore identifies needs for recruiting activities to begin about five quarters ahead of the expected retirement date. Retirements for engineers and first line supervisors began to spike in 2007 and, as a result, many of the new hires over the past year served to fill existing vacancies resulting in a situation where the ideal one year lead time will likely not be attained until 2009. Petitioner's Exhibit TAD-8 shows the staffing plan for engineers and first line supervisors from 2008 through 2012.

Q48. What are the incremental costs of implementing this strategy in your area?

A48. These costs are summarized by Mr. Campbell and are shown in Petitioner's Exhibit LEM-2 sponsored by NIPSCO Witness Linda E. Miller.

Q49. Does this conclude your prepared direct testimony?

A49. Yes, it does.

VERIFICATION

I, Timothy A. Dehring, Senior Vice President, Energy Delivery for Northern Indiana Public Service Company; affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Timothy A. Dehring

Timothy A. Dehring

Date: August 29, 2008

INDS01 DWM 1055960

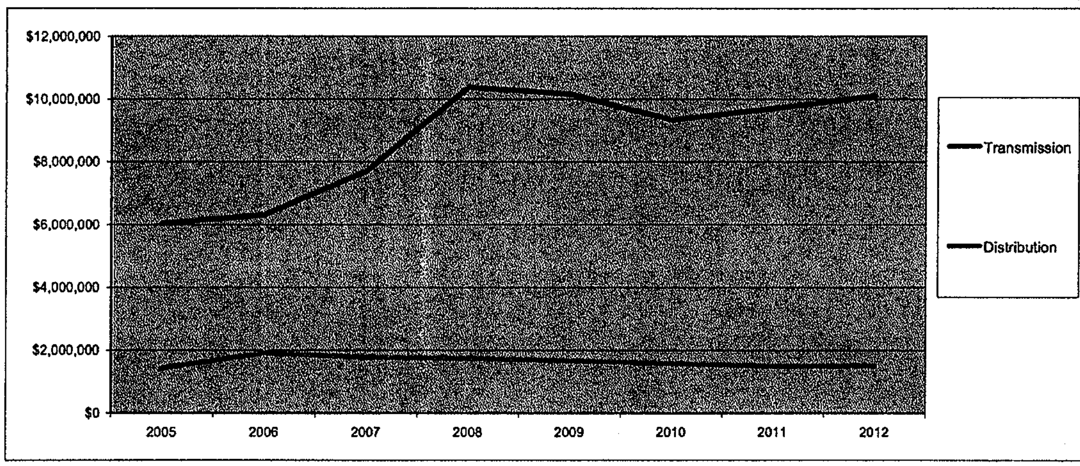
Vegetation Management Work Paper

Description	2005 Actual[1]	2006 Actual[1]	2007 Actual[1]	2008 Budget[1]	[redacted]
Transmission - Rights of Way	$1,441,504	$1,930,114	$1,785,193	$1,763,026	[redacted]
Distribution - Overhead	$6,046,090	$6,323,497	$7,718,972	$10,395,395	[redacted]
Other Vegetation Management Programs	$590,402	$604,987	$645,230	$614,339	[redacted]
Total	$8,077,996	$8,858,599	$10,149,394	$12,772,760	[redacted]

[1] Data Source: CBS reporting

Description	2005 Actual[2]	2006 Actual[2]	2007 Actual[2]	2008 Projected[2]	[redacted]
Distribution Circuit Fixed Bid Expenditures	$3,516,557	$3,461,600	$5,408,500	$8,798,106	[redacted]
Number of circuits cleared	59	80	125	159	[redacted]
Cost per Circuit	$59,603	$43,270	$43,268	$55,334	[redacted]

[2] Data Source: Forestry Operations records



Transmission - Increases in 2005 and 2006 due to NERC adopted reliability standard FAC-003-1. 2007 and forward show slightly declining costs attributable to cost efficiencies of IVM offset by higher clearing costs.

Distribution - Sharp increases through 2008 to achieve a 4 year system cycle time. Years 2009 and 2010 have decreases resulting from lower average cost per circut achieved through reaching the 4 year cycle. Years 2010 and beyond have cost increases reflective of anticipated contractor cost inflation.

Petitioner's Exhibit TAD-3
Northern Indiana Public Service Company
Cause No. 43526

New Safety Related Expenditures

2008

New Safety Expense Item	Prog/Act	Acct Number	Direct Payroll	Incentive	Total Comp	Payroll Benefits @29.97%	Purchases	Total Expense	O&M Portion @75.87%	CAPEX Portion
Initial purchase of FR Clothing for ARC Flash	102-6033	E921.1					$650,000	$650,000	$493,155	$156,845
Initial training for ARC Flash	102-6033	E921.1					$10,000	$10,000	$7,587	$2,413
FR Clothing Annual Refresh	102-6033	E921.1					$0	$0	$0	$0
								$0		
Staffing of 3 Electric Line FTE's for Safety Program	102-9903	E920	$184,518	$5,536	$190,054		$0	$190,054	$144,194	$45,860
Benefits						$55,300		$55,300	$41,956	$13,344
Total O&M Increase for 2008			$184,518	$5,536	$190,054	$55,300	$660,000	$905,354	$686,892	$218,462

2009

New Safety Expense Item	Prog/Act		Direct Payroll	Incentive	Total Comp	Payroll Benefits @29.97%	Purchases	Total Expense	O&M Portion @75.87%	CAPEX Portion
Initial purchase of FR Clothing for ARC Flash	102-6033	E921.1						$0	$0	$0
Initial training for ARC Flash	102-6033	E921.1						$0	$0	$0
FR Clothing Annual Refresh	102-6033	E921.1					$260,000	$260,000	$197,262	$62,738
								$0		
Staffing of 3 Electric Line FTE's for Safety Program	102-9903	E920	$190,071	$5,702	$195,773		$0	$195,773	$148,533	$47,240
						$56,964		$56,964	$43,219	$13,745
Total O&M Increase for 2009			$190,071	$5,702	$195,773	$56,964	$260,000	$512,737	$389,014	$123,724

2010

New Safety Expense Item	Prog/Act		Direct Payroll	Incentive	Total Comp	Payroll Benefits @29.97%	Purchases	Total Expense	O&M Portion @75.87%	CAPEX Portion
Initial purchase of FR Clothing for ARC Flash	102-6033	E921.1						$0	$0	$0
Initial training for ARC Flash	102-6033	E921.1						$0	$0	$0
FR Clothing Annual Refresh	102-6033	E921.1					$260,000	$260,000	$197,262	$62,738
								$0		
Staffing of 3 Electric Line FTE's for Safety Program	102-9903	E920	$190,071	$5,702	$195,773		$0	$195,773	$148,533	$47,240
						$56,964		$56,964	$43,219	$13,745
Total O&M Increase for 2010			$190,071	$5,702	$195,773	$56,964	$260,000	$512,737	$389,014	$123,724

2011

New Safety Expense Item	Prog/Act		Direct Payroll	Incentive	Total Comp	Payroll Benefits @29.97%	Purchases	Total Expense	O&M Portion @75.87%	CAPEX Portion
Initial purchase of FR Clothing for ARC Flash	102-6033	E921.1						$0	$0	$0
Initial training for ARC Flash	102-6033	E921.1						$0	$0	$0
FR Clothing Annual Refresh	102-6033	E921.1					$260,000	$260,000	$197,262	$62,738
								$0		
Staffing of 3 Electric Line FTE's for Safety Program	102-9903	E920	$190,071	$5,702	$195,773		$0	$195,773	$148,533	$47,240
						$56,964		$56,964	$43,219	$13,745
Total O&M Increase for 2011			$190,071	$5,702	$195,773	$56,964	$260,000	$512,737	$389,014	$123,724

2012

New Safety Expense Item	Prog/Act		Direct Payroll	Incentive	Total Comp	Payroll Benefits @29.97%	Purchases	Total Expense	O&M Portion @75.87%	CAPEX Portion
Initial purchase of FR Clothing for ARC Flash	102-6033	E921.1						$0	$0	$0
Initial training for ARC Flash	102-6033	E921.1						$0	$0	$0
FR Clothing Annual Refresh	102-6033	E921.1					$260,000	$260,000	$197,262	$62,738
								$0		
Staffing of 3 Electric Line FTE's for Safety Program	102-9903	E920	$190,071	$5,702	$195,773		$0	$195,773	$148,533	$47,240
						$56,964		$56,964	$43,219	$13,745
Total O&M Increase for 2012			$190,071	$5,702	$195,773	$56,964	$260,000	$512,737	$389,014	$123,724
			$188,960	$5,669	$194,629	$56,631	$340,000	$591,261	$448,589	$142,671

SUMMARY		
E920	Payroll & Incentive	$194,629
E921.1	Purchases	$340,000
C926.1	Benefits	$56,631
C926.5	Capitalized	-$142,671
E408	Payroll Tax 7.65%	$11,296
	Total	$459,886

Five Year Electric Linemen Staffing Model

	2007 Total Staff	2008 Total Staff	2009 Total Staff	2010 Total Staff	2011 Total Staff	2012 Total Staff
Electric Line Staffing Plan						
Beginning of Year Journeyman Staff	**171**	**167**	**171**	**169**	**168**	**178**
Anticipated Retirements	(4)	(10)	(9)	(7)	(7)	(5)
New Apprentice Line Bids	18	17	15	10	11	8
Apprentice Year 2 (Typical Attrition of (1) from Year 1)	10	17	16	14	9	10
Apprentice Year 3	16	10	17	16	14	9
Apprentice Year 4	1	3	6	17	16	14
Total Year 1 & 2 Apprentice Staffing	**28**	**34**	**31**	**24**	**20**	**18**
Total Year 3 & 4 Apprentice Staffing	**17**	**13**	**23**	**33**	**30**	**23**
End of Year Journeymen Staff	**167**	**171**	**169**	**168**	**178**	**189**
Total Line Staff	**212**	**218**	**223**	**225**	**228**	**230**
Electric Line FTE Staffing Plan						
Total Apprentice FTE's (Note 1)	30.4	38.5	46.5	52.0	44.5	37.0
Total Journeyman FTE's (Note 2)	169	169	170	169	173	184
Total Planned Overtime FTE's Required (Note 3)	31	38	27	19	17	14
Total Electric Line FTE Staff	**230.4**	**245.5**	**243.5**	**239.0**	**234.5**	**234.0**
Incremental FTE's vs. Test Year		15.1	13.1	8.6	4.1	3.6
Incremental FTE's vs. Test Year (excluding Safety Initiative)		12.1	10.1	5.6	1.1	0.6
Total Productive Electric Line FTE Staff (Note 4)	**217**	**220**	**220**	**220**	**220**	**220**
Target Productive FTE Staff (Note 5)	**217**	**220**	**220**	**220**	**220**	**220**
Target Planned Overtime FTE's (5% of Journey Staff)	**8**	**9**	**8**	**8**	**9**	**9**

Note 1: For Apprentice FTE calculations, Year 1 Apprentices were staffed for 19% of 2007 & planned at 50% of each year, 2008 and beyond
Note 2: For Journeymen FTE staff, retirements are assumed to occur at mid-year
Note 3: For Overtime FTE calculations, 1,519 overtime hours equal 1 FTE
Note 4: Productive FTE Staff = 3rd & 4th Year Apprentices + Journeymen + Planned OT FTE's
Note 5: Target Productive FTE Staff = Test Year (2007) Productive FTE Staff + 3 for Safety Initiative

Rev: 06-22-08

Five Year Electric Meterman Staffing Model

	2007 Total Staff	2008 Total Staff	2009 Total Staff	2010 Total Staff	2011 Total Staff	2012 Total Staff
Electric Meterman Staffing Plan						
Beginning of Year Journeyman Staff	24	21	24	23	24	22
Anticipated Retirements	(3)	(1)	(2)	(3)	(4)	0
New Apprentice Meterman Bids	4	2	2	2	2	4
Apprentice Year 2	1	4	2	2	2	2
Apprentice Year 3	4	1	4	2	2	2
Total Apprentice Staffing	**9**	**7**	**8**	**6**	**6**	**8**
End of Year Journeymen Staff	**21**	**24**	**23**	**24**	**22**	**24**
Electric Meter FTE Staffing Plan						
Total Apprentice FTE's (Note 1)	7.0	6.0	7.0	5.0	5.0	6.0
Total Journeyman FTE's (Note 2)	22.5	25.5	26.0	28.5	28.0	24.0
Total Electric Meterman FTE Staff	**29.5**	**31.5**	**33.0**	**33.5**	**33.0**	**30.0**
Incremental FTE's vs. Test Year		2.0	3.5	4.0	3.5	0.5
Target Total Staff	**30.0**	**30.0**	**30.0**	**30.0**	**30.0**	**30.0**

Note 1: For Apprentice FTE calculations, Year 1 Apprentices were staffed for 50% of each yeai
Note 2: For Journeymen FTE staff, retirements are assumed to occur at mid-yeai

Rev: 07-15-08

Five Year Substation Electrician Staffing Model

	2007 Total Staff	2008 Total Staff	2009 Total Staff	2010 Total Staff	2011 Total Staff	2012 Total Staff
Substation Electrician Staffing Plan (Note 1)						
Beginning of Year Journeyman Staff	48	48	48	49	49	54
Anticipated Retirements	0	(4)	(6)	(5)	0	(6)
New Apprentice Substation Electrician Bids	5	6	5	2	2	3
Apprentice Year 2	5	5	6	5	2	2
Apprentice Year 3	7	5	5	6	5	2
Apprentice Year 4	4	7	5	5	6	5
Total Apprentice Staffing	**21**	**23**	**21**	**18**	**15**	**12**
End of Year Journeymen Staff	**48**	**48**	**49**	**49**	**54**	**54**
Electric Substation FTE Staffing Plan						
Total Apprentice FTE's (Note 2)	19.8	21.5	19.8	17.5	14.5	11.3
Total Journeyman FTE's (Note 3)	48.0	50.0	52.0	51.5	54.0	57.0
Total Substation Electrician FTE Staff	**67.8**	**71.5**	**71.8**	**69.0**	**68.5**	**68.3**
Incremental FTE's vs. Test Year		3.8	4.0	1.3	0.8	0.5
Target Total Staff	**68.0**	**68.0**	**68.0**	**68.0**	**68.0**	**68.0**

Note 1: Substation Electrician staff includes Service Center Electricians
Note 2: For Apprentice FTE calculations, Year 1 Apprentices were staffed by the end of 1st quarter
Note 3: For Journeymen FTE staff, retirements are assumed to occur at mid-year

Rev: 07-15-08

Five Year Dispatcher Operator Staffing Model

	2007 Total Staff	2008 Total Staff	2009 Total Staff	2010 Total Staff	2011 Total Staff	2012 Total Staff
Dispatcher Operator Staffing Plan						
Beginning of Year Qualified Dispatcher Operators	**13**	**13**	**10**	**12**	**15**	**17**
Anticipated Retirements	0	(6)	(2)	0	0	0
New Dispatcher Operator Trainee Bids	4	4	3	2	0	0
Dispatcher Operator Trainees at End of Year	4	4	3	2	0	0
Newly Qualified Dispatcher Operators by End of Year	**0**	**3**	**4**	**3**	**2**	**0**
Qualified Dispatcher Operators at End of Year	**13**	**10**	**12**	**15**	**17**	**17**
Total Staff	**17**	**14**	**15**	**17**	**17**	**17**
Dispatcher Operator FTE Staffing Plan						
Total Dispatcher Operator Trainee FTE's (Note 1)	2.25	4.50	3.50	2.25	0.50	0.00
Total Qualified Dispatcher Operator FTE's (Note 2)	13.00	12.50	11.75	14.25	16.50	17.00
Total FTE Staff	**15.25**	**17.00**	**15.25**	**16.50**	**17.00**	**17.00**
Incremental FTE's vs. Test Year		1.75	0.00	1.25	1.75	1.75
Target Total Staff (Note 3)	**17.0**	**17.0**	**17.0**	**17.0**	**17.0**	**17.0**

Note 1: For Trainee FTE calculations, see EOY Population notes
Note 2: For Qualified FTE staff, see EOY Population notes
Note 3: Target Total Staff = 17

Rev: 07-15-08

Five Year Staffing Plan for Transmission & Distribution Engineers and Supervisors

# of Engineers	Est Ret Year	Est Ret (End of) Qtr	Hire Year	Hire (End of) Qtr	Recruit Year	Recruit (During) Qtr	Overlap (Aggregate Employee-Years)				
							2008	2009	2010	2011	2012
1	2008	1	2008	1	2007	4	0				
3	2008	3	2008	3	2008	2	0				
6	2008	4	2008	4	2008	3	0				
1	2009	2	2008	4	2008	3		0.50			
1	2009	4	2009	2	2009	1		0.50			
7	2009	4	2009	1	2008	4		5.25			
1	2010	1	2009	1	2008	4		0.75	0.25		
2	2010	2	2009	2	2009	1		1.00	1.00		
3	2010	4	2010	2	2010	1			1.50		
2	2010	4	2009	4	2009	3			2.00		
1	2011	2	2010	2	2010	1			0.50	0.50	
1	2011	3	2010	3	2010	2			0.50	0.50	
1	2011	4	2011	2	2011	1				0.50	
1	2012	4	2012	2	2011	1					0.50
1	2013	3	2012	3	2012	2					0.25
32							0.00	8.00	5.75	1.50	0.75

# of Opns Supervisors	Est Ret Year	Est Ret (End of) Qtr	Hire Year	Hire (End of) Qtr	Recruit Year	Recruit (During) Qtr	Overlap (Aggregate Employee-Years)				
							2008	2009	2010	2011	2012
1	2008	1	2008	1	2007	4	0				
1	2008	3	2008	3	2008	2	0				
2	2008	4	2008	1	2007	4	1.50				
1	2009	1	2008	2	2008	1	0.50	0.25			
1	2009	1	2008	3	2008	2	0.25	0.25			
1	2009	2	2008	2	2008	1	0.50	0.50			
1	2009	3	2009	1	2008	4		0.50			
3	2009	4	2009	1	2008	4		2.25			
1	2010	1	2009	3	2009	2		0.25	0.25		
1	2010	3	2009	4	2009	3			0.75		
1	2010	4	2009	4	2009	3			1.00		
2	2010	4	2010	1	2009	4			1.50		
3	2010	4	2010	2	2010	1			1.50		
3	2011	4	2010	4	2010	3				3.00	
1	2012	4	2012	2	2012	1					0.50
1	2013	1	2012	1	2011	4					0.75
2	2013	3	2012	3	2012	2					0.50
26							2.75	4.00	5.00	3.00	1.75